HECO T-18
DOCKET NO. 2006-0386

TESTIMONY OF

ROGER A. MORIN, Ph.D.

ON BEHALF OF

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate of Return on Common Equity

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HAWAIIAN ELECTRIC COMPANY, INC.

DIRECT TESTIMONY OF DR. ROGER A. MORIN

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INTRODUCTION AND SUMMARY

Q. Please state your name, address, and occupation.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. Please describe your educational background.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. Please summarize your academic and business career.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet, Inc., where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty five years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and on "Utility Capital Allocation," which I have developed on behalf of The Management Exchange Inc. and Exnet in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utility Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released Regulatory Finance, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book, The New Regulatory Finance, has just been published. I have been engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. HECO-1800 describes my professional credentials in more detail.

Q. Have you previously testified on cost of capital before utility regulatory commissions?

A. Yes, I have been a cost of capital witness before nearly fifty (50) regulatory bodies in North America, including the Hawaii Public Utilities Commission ("PUC" or "Commission") in Docket No. 04-0113 (HECO Test Year 2005 Rate Case), the Federal Energy Regulatory Commission, and the Federal Communications Commission. I have also testified before the following state, provincial, and other local regulatory commissions:

Alabama	Hawaii	Nevada	Oregon
Alaska	Illinois	New Brunswick	Pennsylvania
Alberta	Indiana	New Hampshire	Quebec
Arizona	Iowa	New Jersey	South Carolina
Arkansas	Kentucky	New York	South Dakota
British Columbia	Louisiana	Newfoundland	Tennessee
California	Manitoba	North Carolina	Texas
Colorado	Michigan	North Dakota	Utah
Delaware	Minnesota	Nova Scotia	Vermont
District of Columbia	Mississippi	Ohio	Virginia
Florida	Missouri	Oklahoma	Washington
Georgia	Montana	Ontario	West Virginia

The details of my participation in regulatory proceedings are provided in HECO-1800.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on the electric utility operations of the Hawaiian Electric Company, Inc. ("HECO," or "Company") in the State of Hawaii with particular emphasis on the fair return on the Company's common equity capital committed to that business. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to the ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion.

Q. Please briefly identify the exhibits accompanying your testimony.

A. I have attached to my testimony exhibits HECO-1800 through HECO-1809. These exhibits relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. Please summarize your findings concerning HECO's cost of common equity.

A. In order to estimate a fair rate of return on HECO's common equity capital, I have employed the traditional methodologies which assume business-as-usual circumstances and then performed risk adjustments in order to account for HECO's higher than average risk circumstances by virtue of its small relative size and dependence on purchased power. It is my opinion that a just and reasonable return on common equity ("ROE") for HECO is 11.25%.

My recommendation is derived from studies I performed using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methodologies. I performed two CAPM analyses, one using the CAPM and another using an empirical approximation of the CAPM ("ECAPM"). I performed two risk premium analyses: (1) a historical risk premium analysis on the electric utility industry, and (2) a study of the risk premiums reflected in ROEs allowed in the electric utility industry. I also performed DCF analyses on two surrogates for the Company's electric utility business. They are: a group of investment-grade integrated electric utilities that are representative of the electric utility industry and a group consisting of the companies that make up Moody's Electric Utility Index, also representative of the industry. The results from the various methodologies were adjusted to account for the above average risks faced by HECO relative to the industry.

My recommended ROE reflects the application of my professional judgment to the results in light of the indicated returns from my Risk Premium, CAPM, and DCF analyses. Moreover, my recommended return is predicated on the assumption that the Commission will approve: 1) the Company's capital structure for ratemaking purposes which is reflected on HECO-1901 and consists of approximately 55% common equity capital, and 2) the continuation of the

Company's current energy cost adjustment clause in the same manner as in the past.

Q. Please explain how low allowed ROES can increase both the future cost of equity and debt financing.

A. If a utility is authorized a ROE below the level required by equity investors, the utility will find it difficult to access the equity market through common stock issuance at its current market price. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a utility that has been authorized a return below the level investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This reduces the financial viability of equity financing in two ways. First, because the utility's share price per common stock decreases, the net proceeds from issuing common stock are reduced. Second, since the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

As the company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth.

Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment. The risk of default on the company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that HECO has access to capital markets for its capital needs, a fair and reasonable authorized rate of return on common equity capital of 11.25% is required.

Q. Please describe how your testimony is organized.

A. The remainder of my testimony is divided into three (3) sections:

(i) Regulatory Framework and Rate of Return;
(ii) Cost of Equity Estimates; and
(iii) Summary and Recommendation

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests. In the third section, the results from the various approaches used in determining a fair return are summarized.

I. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. What economic and financial concepts have guided your assessment of the Company's cost of common equity?

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity, one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk. On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. How does HECO's cost of capital relate to that of its parent company, Hawaiian Electric Industries, Inc. ("HEI")?

A. I am treating HECO as a separate stand-alone entity, distinct from the parent company HEI because it is the cost of capital for HECO that we are attempting to measure and not the cost of capital for HEI's consolidated activities. Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost to the investor, in this case, HEI. The true cost of capital depends on the use to which the capital is put, in this case HECO's electric utility operations in the State of Hawaii. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost but rather the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on HECO is the return foregone in comparable risk electricity utility operations, and is unrelated to the parent's cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations should behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Therefore, the cost of investing funds in an operating utility subsidiary such as HECO is the return foregone on investments of similar risk and is unrelated to the identity of the investor.

Q. Please explain how a regulated company's rates should be set under traditional cost of service regulation.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of the next section of my testimony to estimate HECO's cost of common equity capital.

Q. Dr. Morin, what must be considered in estimating a fair return on common equity?

A. The legal requirement is that the allowable ROE should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness, and ability to attract capital on reasonable terms. The attraction of capital standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, CAPM, or DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from investments of comparable risk.

Q. What fundamental tenets underlie the determination of a fair and reasonable ROE?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

2. Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944).

The Bluefield case set the standard against which just and reasonable rates of return are measured:

> "*A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties ... The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.*" (Emphasis added)

The Hope case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the Bluefield case and recognized that revenues must cover "capital costs." The Court stated:

> "*From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock ... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.*" (Emphasis added)

The United States Supreme Court reiterated the criteria set forth in Hope in Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S.

458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory agency's rate of return order should:

> *"...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed..."*

Therefore, the "end result" of this Commission's decision should be to allow HECO the opportunity to earn a ROE that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the company's financial integrity, and (3) sufficient to maintain the company's creditworthiness and ability to attract capital on reasonable terms.

Q. How is the fair rate of return determined?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility. It is the composite weighted cost of the various classes of capital (bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

While utilities like HECO enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on common and/or preferred equity.

Q. How does the concept of a fair return relate to the concept of opportunity cost?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they also are exposing their funds to risk and forgoing returns from investing their money in alternative comparable-risk investments. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. These differences in risk are translated by the capital markets into price differences in much the same way that differences in the characteristics of commodities are reflected in different prices. The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for the respective securities and the risks expected from the overall menu of available securities.

Q. How does the Company obtain its capital and how is its overall cost of capital determined?

A. The funds employed by the Company are obtained in two general forms, debt capital and equity capital. The latter consists of preferred equity capital and common equity capital. The cost of debt funds and preferred stock funds can be ascertained easily from an examination of the contractual terms for the interest payments and preferred dividends. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt and preferred stock, based on the utility's capital structure, in order to arrive at the overall cost of capital.

Q. What is the market required rate of return on equity capital?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments, and the returns available from other investments of comparable risk.

II. COST OF EQUITY CAPITAL ESTIMATES

Q. Dr. Morin, how did you estimate the fair rate of return on common equity for HECO?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF methodologies. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to HECO. I have applied the aforementioned methodologies to samples of average risk utilities representative of the electric utility industry as a whole and adjusted the results upward to recognize HECO's higher relative risk.

Q. Why did you use more than one approach for estimating the cost of equity?

A. No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

Q. Are there any difficulties in applying cost of capital methodologies in the current environment of changes in the electric utility industry?

A. Yes, there are. All the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the electric utility industry. This is because utility company historical data have become less meaningful for an industry in a state of change. Past earnings and dividend trends are simply not indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including structural transformation, restructuring, and the transition to a more competitive environment. As a result, this historical data may not be representative of the future long-term earning power of these companies. Moreover, historical growth rates may not be representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available.

Q. Dr. Morin, are you aware that some regulatory commissions and some analysts have placed principal reliance on DCF-based analyses to determine the cost of equity for public utilities?

A. Yes, I am.

Q. Do you agree with this approach?

A. While I agree that it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. As I have stated, there are three broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methodologies are accepted and used by the financial community and firmly supported in the financial literature.

When measuring the cost of common equity, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component, are vivid examples of the potential shortcomings of the DCF model. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that all of these methodologies should be applied to multiple groups of comparable risk companies.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. Absent any hard evidence as to which method outperforms the other, all relevant evidence should be used, without discounting the value of any results, in order to minimize judgmental error, measurement error, and conceptual infirmities. A regulatory body should rely on the results of a variety of methods applied to a variety of comparable groups. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of a stock's price or the cost of equity.

Q. Does the financial literature support the use of more than a single method?

A. Yes, definitely. Authoritative financial literature strongly supports the use of multiple methods. For example, Professor Eugene F. Brigham, a widely respected scholar and finance academician, asserts:

> *In practical work, it is often best to use all three methods - CAPM, bond yield plus risk premium, and DCF - and then apply judgment when the methods produce different results. People experienced in estimating capital costs recognize that both careful analysis and some very fine judgments are*

> *required. It would be nice to pretend that these judgments are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible.*[1]

In a subsequent edition of his best-selling corporate finance textbook, Dr. Brigham discusses the various methods used in estimating the cost of common equity capital, and states:

> *However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive - no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company' cost of equity, we generally use all three methods...*[2]

Another prominent finance scholar, Professor Stewart Myers, in his best selling corporate finance textbook, points out:

> *The constant growth [DCF] formula and the capital asset pricing model are two different ways of getting a handle on the same problem.*[3]

In an earlier article, Professor Myers explains:

> *Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.*[4]

Q. Doesn't the wide use of the DCF methodology in past regulatory proceedings indicate that it is superior to other methods?

A. No, it does not. Uncritical acceptance of the standard DCF equation vests the model with a degree of infallibility that is not necessarily present. One of the

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[1] E. F. Brigham and L. C. Gapenski, Financial Management Theory and Practice, p. 256 (4th ed., Dryden Press, Chicago, 1985)
[2] E. F. Brigham and L. C. Gapenski, Financial Management Theory and Practice, p. 348 (8th ed., Dryden Press, Chicago, 2005)
[3] R. A. Brealey and S. C. Myers, Principles of Corporate Finance, p. 182 (3rd ed., McGraw Hill, New York, 1988)
[4] S. C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," Financial Management, p. 67 (Autumn 1978)

leading experts on public utility regulation, Dr. Charles Phillips, discusses the dangers of relying solely on the DCF model:

> *[U]se of the DCF model for regulatory purposes involves both theoretical and practical difficulties. The theoretical issues include the assumption of a constant retention ratio (i.e. a fixed payout ratio) and the assumption that dividends will continue to grow at a rate 'g' in perpetuity. Neither of these assumptions has any validity, particularly in recent years. Further, the investors' capitalization rate and the cost of equity capital to a utility for application to book value (i.e. an original cost rate base) are identical only when market price is equal to book value. Indeed, DCF advocates assume that if the market price of a utility's common stock exceeds its book value, the allowable rate of return on common equity is too high and should be lowered; and vice versa. Many question the assumption that market price should equal book value, believing that "the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.*
>
> *...[T]here remains the circularity problem: Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. For all of these reasons, the DCF model 'suggests a degree of precision which is in fact not present' and leaves 'wide room for controversy about the level of k [cost of equity]'.*[5]

Dr. Phillips also discusses the dangers of relying solely on the CAPM model because of the stringency of certain of its underlying assumptions, as is the case for any model in the social sciences.

Sole reliance on the DCF model simply ignores the capital market evidence and investors' use of other theoretical frameworks such as the Risk Premium and CAPM methodologies. The DCF model is only one of many tools to be employed to estimate the cost of equity. It is not a superior methodology which supplants other financial theory and market evidence. The same is true of the CAPM.

Q. Does the DCF model understate the cost of equity?

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[5] C. F. Phillips, *The Regulation of Public Utilities Theory and Practice*, pp. 376-77. (Public Utilities Reports, Inc., 1988) pp. 376-77. [Footnotes omitted]

A. Yes, it does. Application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the Market-to-Book (M/B) ratio is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds unity. This item is particularly relevant in the current capital market environment where utility stocks are trading at M/B ratios well above unity and have been for two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.

Q. Can you illustrate the effect of the M/B ratio on the DCF model by means of a simple example?

A. Yes. The simple numerical illustration shown in the table below demonstrates the result of applying a market value cost rate to book value rate base under three different M/B scenarios. The three columns correspond to three M/B situations: the stock trades below, equal to, and above book value, respectively. The last situation (boxed portion of the table) is noteworthy and representative of the current capital market environment. The DCF cost rate of 10%, made up of a 5% dividend yield and a 5% growth rate, is applied to the book value rate base of \$50 to produce \$5.00 of earnings. Of the \$5.00 of earnings, the full \$5.00 are required for dividends to produce a dividend yield of 5% on a stock price of \$100.00, and no dollars are available for growth. The investor's return is therefore only 5% versus his required return of 10%. A DCF cost rate of 10%, which implies \$10.00

of earnings, translates to only $5.00 of earnings on book value, a 5% return.

The situation is reversed in the first column when the stock trades below book value. The $5.00 of earnings are more than enough to satisfy the investor's dividend requirements of $1.25, leaving $3.75 for growth, for a total return of 20%. This item occurs when the DCF cost rate is applied to a book value rate base well above the market price.

Therefore, the DCF cost rate understates the investor's required return when stock prices are well above book, as is the case presently.

EFFECT OF MARKET-TO-BOOK RATIO ON MARKET RETURN

		Situation 1	*Situation 2*	*Situation 3*
1	Initial purchase price	$25.00	$50.00	$100.00
2	Initial book value	$50.00	$50.00	$ 50.00
3	**Initial M/B**	**0.50**	**1.00**	**2.00**
4	**DCF Return 10% = 5% + 5%**	**10.00%**	**10.00%**	**10.00%**
5	Dollar Return	$5.00	$5.00	$5.00
6	Dollar Dividends 5% Yield	$1.25	$2.50	$5.00
7	Dollar Growth 5% Growth	$3.75	$2.50	$0.00
8	***Market Return***	**20.00%**	**10.00%**	**5.00%**

Q. Does the annual version of the DCF model understate the cost of equity?

A. Yes, it does. Another reason why the DCF methodology understates the cost of equity is that the annual DCF model usually employed in regulatory settings assumes that dividend payments are made annually at the end of the year, while most utilities in fact pay dividends on a quarterly basis. Failure to recognize the quarterly nature of dividend payments understates the cost of equity capital by about 30 basis points. By analogy, a bank rate on deposits which does not take into consideration the timing of the interest payments understates the true yield of your investment if you receive the interest payments more than once a year. Since the stock price employed in the DCF model already reflects the quarterly stream of dividends to be received, consistency therefore requires explicit recognition of the quarterly nature of dividend payments. One only has to think of what would happen to a company's stock price if the company was to suddenly announce that it is, from now on, paying dividends once a year at the end of the year instead of four times a year each quarter. Clearly, the stock price would decline by an amount reflecting the lost time value of money.

Q. Do regulators rely primarily on the DCF model?

A. No, I believe that a majority of regulatory commissions do not, as a matter of practice, rely solely on the DCF model results in setting the allowed rate of return on common equity. According to the results posted in a survey conducted by the National Association of Regulatory Utility Commissioners ("NARUC"), regulators utilize a variety of methods and rely on all the evidence submitted.

Q. Do regulators share your reservations on the reliability of the DCF model?

A. Yes, I believe they do. While a majority of regulatory commissions do not, as a matter of practice, rely solely on the DCF model results in setting the allowed rate of return on common equity, some regulatory commissions have explicitly recognized the need to avoid exclusive reliance upon the DCF model and have acknowledged the need to adjust the DCF result when M/B ratios exceed one[6].

My sentiments on the DCF model were echoed in a decision by the Indiana Utility Regulatory Commission (IURC). The IURC recognized its concerns with

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[6] See the Indiana Utility Regulatory Commission decision in Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18. See also the Iowa Utilities Board decision in U.S. West Communications, Inc., Docket No., RPR-93-9, 152 PUR4th 459. See also the Hawaii Public Utilities Commission decision in Hawaiian Electric Company, Inc., Docket No. 6998, PUR4th 134. More recently, see the Pennsylvania Public Utility Commission decision in Pennsylvania-American Water Company, Docket 130680, PUR4th, 1/25/02.

the DCF model and that the model understates the cost of equity. In Cause No. 39871 Final Order, the IURC states on page 24:

> *"....the DCF model, heavily relied upon by the Public, understates the cost of common equity. The Commission has recognized this fact before. In Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18, we found:*
>
> *The unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible, and therefore requires an upward adjustment based largely on the expert witness's judgment."*

The Commission also expressed its concern with a witness relying solely on one methodology:

> *"......the Commission has had concerns in our past orders with a witness relying solely on one methodology in reaching an opinion on a proper return on equity figure." (page 25)*

Even more convincing is the fact that M/B ratios have exceeded unity for over two decades; this fact is clear evidence that regulators have in fact not relied on the DCF model exclusively. Had regulators relied exclusively on the DCF model, utility stocks would have traded at or near book value. Regulators have "corrected" for this chronic M/B problem by considering alternative methods for estimating capital cost.

Q. Is the usage of the DCF model prevalent in corporate practices?

A. No, not really. The CAPM continues to be widely used by analysts, investors, and corporations. Bruner, Eades, Harris, and Higgins (1998) in a comprehensive survey[7] of current practices for estimating the cost of capital found that 81% of companies used the CAPM to estimate the cost of equity, 4% used a modified CAPM, and 15% were uncertain. In another comprehensive survey conducted by Graham and Harvey

[7]Bruner, R. F., Eades, K. M., Harris, R. S., and Higgins, R. C., "Best Practices in Estimating the Cost of Capital: Survey and Synthesis," *Financial Practice and Education,* Vol. 8, Number 1, Spring/Summer 1998, page 18.

(2001), the managers surveyed reported using more than one methodology to estimate the cost of equity, and 73% used the CAPM.[8] Since its introduction by Professor William F. Sharpe in 1964, the CAPM has gained immense popularity as the practitioner's method of choice when estimating cost of capital under conditions of risk.[9] The intuitive simplicity of its basic concept (that investors must get compensated for the risk they assume), and the relatively easy application of the CAPM are the main reasons behind its popularity.

Q. Do the assumptions underlying the DCF model require that the model be treated with caution?

A. Yes, particularly in today's rapidly changing electric utility industry. Even ignoring the fundamental thesis that several methods and/or variants of such methods should be used in measuring equity costs, the DCF methodology, as those familiar with the industry and the accepted norms for estimating the cost of equity are aware, is problematic for use in estimating cost of equity at this time.

Several fundamental structural changes have transformed the electric utility industry since the standard DCF model and its assumptions were developed. For example, deregulation, increased wholesale competition triggered by national policy, changes in customer attitudes regarding utility services, the evolution of alternative energy sources, highly volatile fuel prices, and mergers-acquisitions have all influenced stock prices in ways that have deviated substantially from the assumptions of the DCF model. These changes suggest that some of the fundamental assumptions underlying the standard DCF model, particularly that of constant growth and constant relative market valuation, for example

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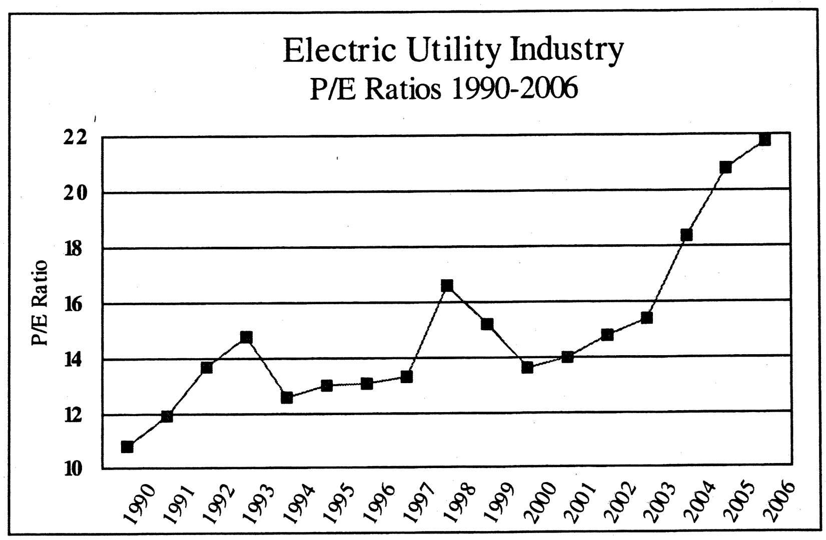
[8]Graham, J. R. and Harvey, C. R., "The Theory and Practice of Corporate Finance: Evidence from the Field," *Journal of Financial Economics*, Vol. 61, 2001, pp. 187-243.
[9] See practitioner surveys by Graham & Harvey (2001) and Bruner, et. al. (1988)

price/earnings (P/E) ratios and M/B ratios, are problematic at this point in time for utility stocks, and that, therefore, alternate methodologies to estimate the cost of common equity should be accorded at least as much weight as the DCF method.

Q. Is the constant relative market valuation assumption inherent in the DCF model always reasonable?

A. No, not always. Caution must be exercised when implementing the standard DCF model in a mechanistic fashion, for it may fail to recognize changes in relative market valuations over time. The traditional DCF model is not equipped to deal with surges in M/B and P/E ratios. The standard DCF model assumes a constant market valuation multiple, that is, a constant P/E ratio and a constant M/B ratio. Stated another way, the model assumes that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current ratio of market price to dividend (or earnings), and that the stock price will grow at the same rate as the book value. This item is a necessary result of the infinite growth assumption. This assumption is unrealistic under current conditions as the graph below clearly demonstrates. The DCF model is not equipped to deal with sudden surges in M/B and P/E ratios, as was experienced by utility stocks in recent years.



Q. What is your recommendation given such market conditions?

A. Caution and judgment are required in interpreting the results of the standard DCF model because of: (1) the effect of changes in risk and growth on electric utilities, (2) the fragile applicability of the DCF model to utility stocks in the current capital market environment, and (3) the practical difficulties associated with the growth component of the standard DCF model. Hence, there is a clear need to go beyond the standard DCF results and take into account the results produced by alternate methodologies in arriving at a common equity recommendation.

Q. Do the assumptions underlying the CAPM require that the model be treated with caution?

A. Yes, as was the case with the DCF model, the assumptions underlying any model in the social sciences, including the CAPM, are stringent. Moreover, the empirical validity of the CAPM has been the subject of intense research in recent years. Although the CAPM provides useful evidence, it must be complemented by other methodologies as well.

Q. Are the assumptions underlying the CAPM any more or less confining than those underlying the DCF model?

A. I believe that the assumptions underlying the CAPM are less stringent than those underlying the DCF theory. This becomes apparent if we view the CAPM as a special case of the Arbitrage Pricing Model (APM), where the market portfolio is the only factor affecting security prices. The assumptions underlying the APM are far less stringent than the assumptions required for the DCF model to obtain. The APM derives from only two major reasonable assumptions: (1) that security returns are linear functions of several economic factors, and (2) that no profitable arbitrage opportunities exist since investors are able to eliminate such opportunities through risk-free arbitrage transactions. The other assumptions required by the APM are that investors are greedy and risk averse, that they can diversify company-specific risks by holding large portfolios, and that enough investors possess similar expectations to trigger the arbitrage process.

As a tool in the regulatory arena, the CAPM is a rigorous conceptual framework, and is logical insofar as it is not subject to circularity problems, since its inputs are objective, market-based quantities, largely immune to regulatory decisions. The data requirements of the model are not prohibitive. The CAPM is one of several tools in the arsenal of techniques to determine the cost of equity capital. Caution, appropriate training in finance and econometrics, and judgment are required for its successful execution, as is the case with the DCF and Risk Premium methodologies.

Q. Dr. Morin, please provide an overview of your risk premium analyses.

A. In order to quantify the risk premium for HECO, I have performed four risk premium studies. The first two studies deal with aggregate stock market risk premium evidence using two versions of the CAPM methodology and the other two studies deal directly with the electric utility industry.

A. **CAPM Estimates**

Q. Please describe your application of the CAPM risk premium approach.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium determined by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). In order to estimate the CAPM return for the average risk electric utility, I used a risk-free rate of 4.9%, a beta estimate of 0.86 and a market risk premium estimate of 7.4%. These respective inputs to the CAPM are explained below.

Q. What risk-free rate did you use in your CAPM and risk premium analyses?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the current level of 30-year Treasury bond yields.

The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term or intermediate-term Treasury notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

Another reason for utilizing the longest maturity Treasury bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return will therefore be equal to the inflation rate anticipated to prevail over the very long-term. The same expectation should be embodied in the risk free rate used in applying the CAPM model. It stands to reason that the yields on 30-year Treasury bonds will more closely incorporate within their yield the inflation expectations that influence the prices of common stocks than do short-term or intermediate-term U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yield on such securities should be used as proxies for the risk-free rate in applying the CAPM, provided there are no anomalous conditions existing in the 30-year Treasury market. In the absence of such conditions, I have relied on the yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

Q. Dr. Morin, why did you reject short-term interest rates as proxies for the risk-free rate in implementing the CAPM?

A. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes no sense to match the return on common stock to the yield on 90-day Treasury Bills. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

Q. What is the current level of U.S. Treasury 30-year bonds?

A. The yield on U.S. Treasury 30-year bonds prevailing in October 2006, as reported in Bloomberg.com and Value Line, was 4.9%. Accordingly, I use 4.9% as my estimate of the risk-free rate component of the CAPM.

Q. How did you select the beta for your CAPM analysis?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta", or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. It indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation which are reflected in investors' return requirements.

As a proxy for the beta of the electric utility industry, I examined the betas of a sample of widely-traded investment-grade electric utilities covered by Value Line. This group is examined in more detail later in my testimony, in connection with the DCF estimates of the cost of common equity. As displayed on page 1 of Exhibit HECO-1801, the average beta for the group is currently 0.86. I also examined the average beta of the companies that make up Moody's Electric Utility Index as a proxy for the electric utility industry. As shown on page 2 of Exhibit HECO-1801, the average beta of the Moody's group is 0.92. Of course, to the extent that HECO is riskier than average, the beta applicable to HECO is correspondingly higher.

Based on these results, I shall use 0.86 as my estimate for the beta applicable to the average risk electric utility. I reiterate that to the extent that HECO is riskier than average, the beta applicable to HECO is correspondingly higher.

Q. What market risk premium ("MRP") estimate did you use in your CAPM analysis?

A. For the MRP, I used 7.4%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. First, the Ibbotson Associates study, Stocks, Bonds, Bills, and Inflation, 2006 Yearbook, compiling historical returns from 1926 to 2005, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 6.5%. The historical MRP over the income component of long-term Treasury bonds rather than over the total return is 7.1%. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical MRP, and I concur with this viewpoint. The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. The more accurate way to estimate the MRP from historic data is to use the income return, not total returns on government bonds, as explained at page 66 of Ibbotson Associates, Stocks, Bonds, Bills, and Inflation: Valuation Edition, 2005 Yearbook. This is because the income component of total bond return (*i.e.* the coupon rate) is a far better estimate of expected return than the total return (*i.e.* the coupon rate + capital gain), as realized capital gains/losses are largely unanticipated by bond investors. The long-horizon (1926-2005) MRP (based on income returns, as required) is specifically calculated to be 7.1% rather than 6.5%.

Second, a DCF analysis applied to the aggregate equity market using Value Line's aggregate stock market index and growth forecasts indicates a prospective MRP of 7.8%. The average of the historical (7.1%) and prospective estimates (7.8%), which is 7.4%, provides a reasonable estimate of the MRP.

Q. On what maturity bond does the Ibbotson historical risk premium data rely on?

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2005 long period covered in the Ibbotson Associate Study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. To the extent that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Ibbotson study, the difference in yield is not material. In fact, the difference in yield between 30-year and 20-year bonds is actually negative. The average difference in yield over the 1977-2006 period is 13 basis points, that is, the yield on 20-year bonds is slightly higher than the yield on 30-year bonds.

Q. Why did you use long time periods in arriving at your historical MRP estimate?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the MRP with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate MRP minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, the best estimate of the future risk premium is the historical mean. Since I found no evidence that the MRP in common stocks has changed over time, that is, no significant serial correlation in the Ibbotson study, it is reasonable to assume that these quantities will remain stable in the future.

Q. Please describe your prospective approach in deriving the MRP in the CAPM analysis.

A. For my prospective estimate of the MRP, I applied a DCF analysis to the aggregate equity market using Value Line's VLIA software. The dividend yield on the dividend-paying stocks that make up the Value Line Composite index made up of some 1800 stocks is currently 1.20% (VLIA 10/2006 edition), and the average projected dividend growth rate is 11.2%. Adding the dividend yield to the growth component produces an expected return on the aggregate equity market of 12.4%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 12.5%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings the MRP estimate to approximately 12.7%. Subtracting the risk-free rate of 4.9% from the latter, the implied risk premium is 7.8% over long-term U.S. Treasury bonds. The average of the historical (7.1%) and prospective MRP (7.8%) estimate is 7.4%.

As a check on my MRP estimate, I examined a recent 2003 comprehensive article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") that provides estimates of the ex ante expected returns for S&P 500 companies over the period 1983-1998[10]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each

[10] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

month from January 1983 to August 1998 by using the constant growth DCF model. The prevailing risk-free rate for each year was then subtracted from the expected rate of return for the overall market to arrive at the MRP for that year. The table below, drawn from HMMO Table 2, displays the average prospective risk premium estimate for each year from 1983 to 1998. The average MRP estimate for the overall period is 7.2%, which is close to my estimate of 7.4%.

Market Risk Premium Estimates

Year	DCF Market Risk Premium
1983	6.6%
1984	5.3%
1985	5.7%
1986	7.4%
1987	6.1%
1988	6.4%
1989	6.6%
1990	7.1%
1991	7.5%
1992	7.8%
1993	8.2%
1994	7.3%
1995	7.7%
1996	7.8%
1997	8.2%
1998	9.2%
MEAN	7.2%

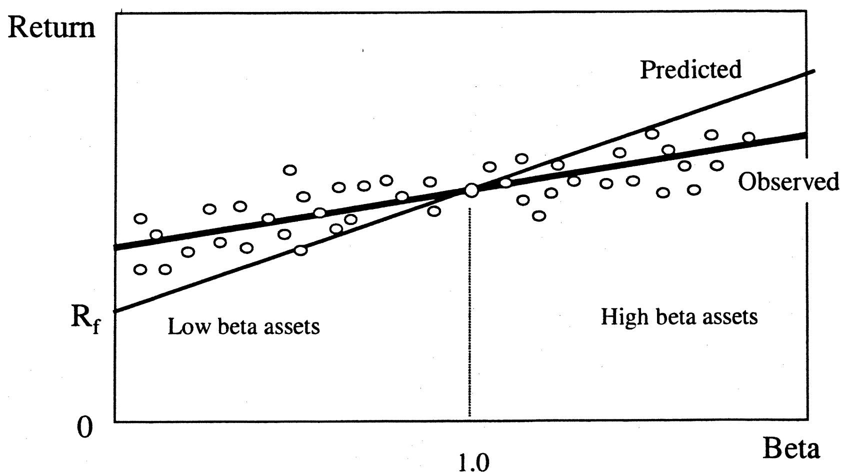
Q. What is your risk premium estimate of the company's cost of equity using the CAPM approach?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 4.9%, a beta of 0.86, and a MRP of 7.4%, the CAPM estimate of the cost of common equity for HECO is: 4.9% + 0.86 x 7.4% = 11.3%. This estimate becomes 11.6% with flotation costs, discussed later in my testimony.

Q. What is your risk premium estimate using the empirical version of the CAPM?

A. There have been countless empirical tests of the CAPM in the finance literature in order to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 13 of my 1994 book, Regulatory Finance, and Chapter 6 of my latest book, The New Regulatory Finance, both published by Public Utilities Report Inc. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

CAPM: Predicted vs Observed Returns



A number of variations on the original CAPM theory have been proposed to explain this finding. The empirical version of the CAPM ("ECAPM") makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \acute{\alpha} + \beta \times (MRP - \acute{\alpha})$$

where ά is the "alpha" of the risk-return line, a constant, MRP is the market risk premium ($R_M - R_F$), and the other symbols are defined as usual. Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than the use of raw betas also incorporates some of the desired effect of using the ECAPM. Thus, it is reasonable to apply a conservative alpha adjustment.

Q. Is the use of the ECAPM consistent with the use of adjusted betas?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line, Bloomberg, and Ibbotson Associates. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the observed return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

Exhibit HECO-1808 contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings. In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta\,(R_M - R_F)$$

Inserting 4.9% for the risk-free rate R_F, a MRP of 7.4% for (R_M - R_F) and a beta of 0.86 in the above equation, the return on common equity is 11.5% without flotation costs and 11.8% with flotation costs.

Q. Dr. Morin, please summarize your CAPM estimates.

A. The table below summarizes the common equity estimates obtained from my CAPM studies. The average CAPM result is 11.7%.

CAPM

	%ROE
CAPM	11.6%
Empirical CAPM	11.8%
AVERAGE	11.7%

B. Risk Premium Estimates

Q. Please describe your historical risk premium analysis of the electric utility industry.

A. As a proxy for the risk premium applicable to the electric utility industry, I estimated the historical risk premium for the electric utility industry with an annual time series analysis applied to the industry as a whole, using *Moody's Electric Utility Index* as an industry proxy. The analysis is depicted on Exhibit

HECO-1802. The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. Data for this particular index was unavailable beyond 2001 following the acquisition of Moody's by Mergent.

As shown on Exhibit HECO-1802, the average risk premium over the period was 5.6% over long-term Treasury bonds. Given that the risk-free rate is 4.9%, the implied cost of equity for the average electric utility from this particular method is 4.9% + 5.6% = 10.5% without flotation costs and 10.8% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony. I reiterate that to the extent that HECO is riskier than average, the risk premium applicable to HECO is correspondingly higher.

Q. How does the inclusion of recent risk premium data alter these results?

A. The historical risk premium analysis for the electric utility industry stops in 2001 because the annual Moody's Public Utility Manual from which the data were drawn was discontinued following the acquisition of Moody's by Mergent in 2002. In view of the rising risk premium allowed by regulators documented in the next section of my testimony, it would not be unreasonable to expect that the current utility risk premium exceeds the historical average. I examined some more recent historical bond return and equity return data based on the S&P Utility Index instead of Moody's Electric Utility Index. The addition of 2002-2005 data slightly raises the historical risk premium slightly. This result is not surprising in view of the rising equity market in the 2003-2005 period.

Q. Dr. Morin, are risk premium studies widely used?

A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, and expert witnesses. Most college-level corporate finance and/or investment management texts including Investments by Bodie, Kane, and Marcus, McGraw-Hill Irwin, 2002, which is a recommended textbook for CFA (Chartered Financial Analyst) certification and examination, contain detailed conceptual and empirical discussion of the risk premium approach. The latter is typically recommended as one of the three leading methods of estimating the cost of capital. Professor Brigham's best-selling corporate finance textbook (Financial Management: Theory and Practice, 11th ed., South-Western, 2005), recommends the use of risk premium studies, among others. Techniques of risk premium analysis are widespread in investment community reports. Professional certified financial analysts are certainly well versed in the use of this method.

Q. Are you concerned about the realism of the assumptions that underlie the historical risk premium method?

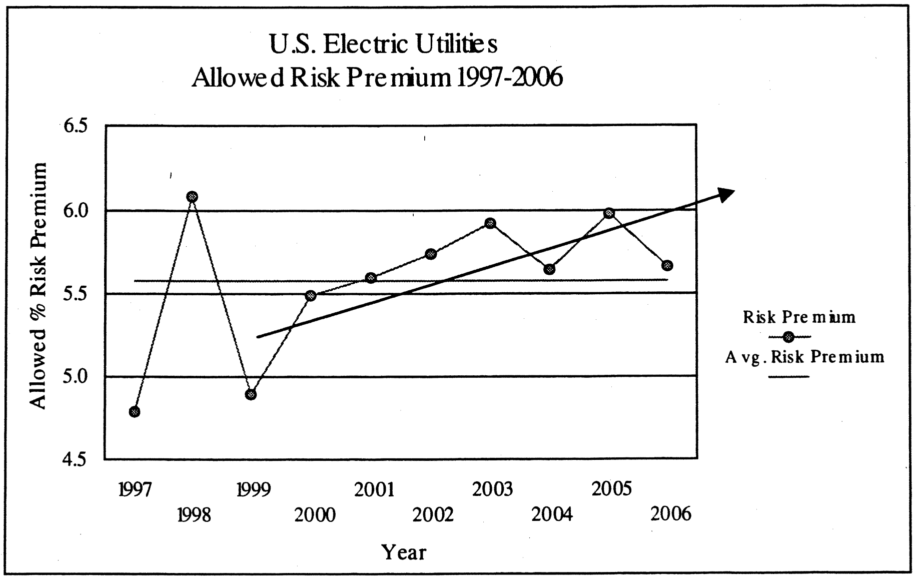
A. No, I am not, for they are no more restrictive than the assumptions that underlie the DCF model or the CAPM. While it is true that the method looks backward in time and assumes that the risk premium is constant over time, these assumptions are not necessarily restrictive. By employing returns realized over long time periods rather than returns realized over more recent time periods, investor return expectations and realizations converge. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. By ensuring that the risk premium study encompasses the longest possible period for which data are available, short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would never commit any funds.

C. <u>Allowed Risk Premiums</u>

Q. Please describe your analysis of allowed risk premiums in the electric utility industry.

A. To estimate the Company's cost of common equity, I also examined the historical risk premiums implied in the ROEs allowed by regulatory commissions for electric utilities over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, Risk Premium, CAPM, etc.) presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace. Historical allowed ROE data are readily available over long periods on a quarterly basis from Regulatory Research Associates (RRA) and easily verifiable from RRA publications and past commission decision archives.

The average ROE spread over long-term Treasury yields was 5.6% for the 1997-2006 time period, as shown by the horizontal line in the graph below. I note that this estimate is identical to that obtained from the historical risk premium study of the electric utility industry. The graph also shows the year-by-year allowed risk premium. The steady escalating trend of the risk premium in response to lower interest rates and rising competition is noteworthy.

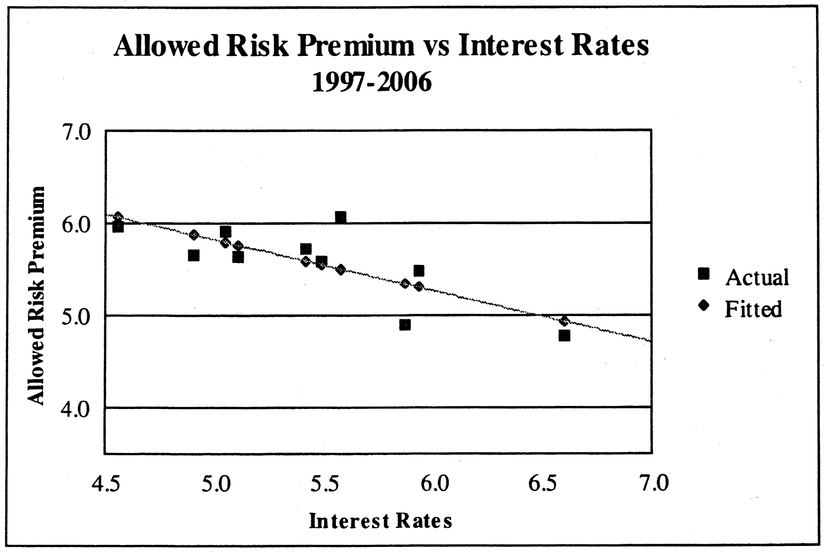


A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the last decade:

$$RP = 8.6029 - \underset{(t = 3.3)}{0.5543}\ YIELD \qquad R^2 = 0.58$$

The relationship is highly statistically significant[11] as indicated by the high R^2 and statistically significant t-value of the slope coefficient. The graph below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.

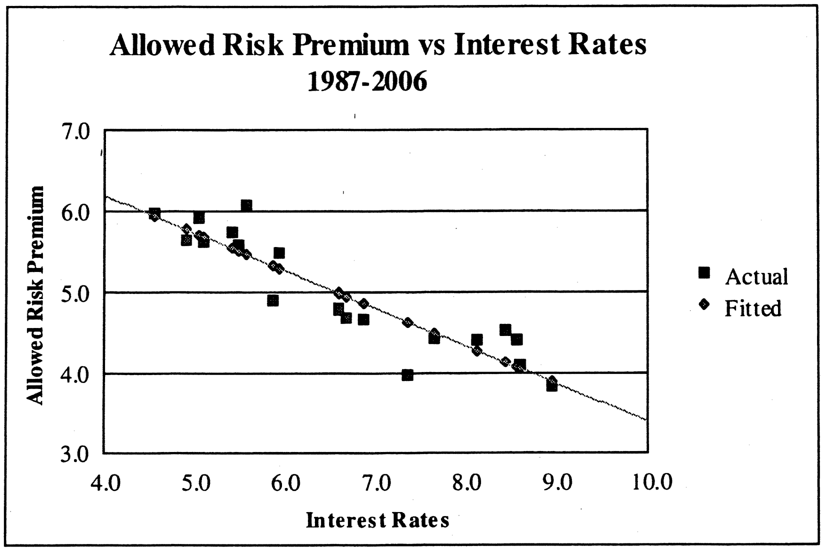
[11] The coefficient of determination R^2, sometimes called the "goodness of fit measure" is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample data. The t-statistic is a standard measure of the statistical significance of an independent variable in a regression relationship. A t-value above 2.0 is considered highly significant.



Inserting the current long-term Treasury bond yield of 4.9% in the above equation suggests that a risk premium estimate of 5.9% should be allowed for the average risk electric utility, implying a cost of equity of 10.8% for the average risk utility. No flotation cost adjustment is required here since the return figures are allowed book returns on common equity capital.

Q. Dr. Morin, does the observed relationship between allowed utility returns and interest rates hold over longer periods as well?

A. Yes, it does indeed. The relationship is even more significant over longer periods with a R^2 of 0.83 and a t-value of 9.5. The graph below illustrates the inverse relationship between the allowed risk premium and interest rates as revealed in some 550 past ROE decisions over the longest period over which such data are available from RRA, namely 1987-2006.



Q. Why did you rely on the last decade to conduct your allowed risk premium analysis?

A. Because allowed returns already reflect investor expectations, that is, are forward-looking in nature, the need for relying on long historical periods is minimized. The last decade is a reasonable period of analysis in the case of allowed returns in view of the stability of the inflation rate experienced over the last decade.

Q. Do investors take into account allowed returns in formulating their expectations?

A. Yes, they do. Investors do take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value Line and RRA. Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless an important determinant of investor growth perceptions and investor expected returns.

Q. Do allowed returns reflect investor expectations?

A. As far as allowed risk premiums are concerned, regulators presumably base their allowed ROE decisions relative to the level of interest rates on a wide variety of evidence concerning investor expected returns submitted by various parties. Because allowed returns already reflect investor expectations, that is, are forward-looking in nature, the need for relying on long historical periods is minimized. The last decade is a reasonable period of analysis in the case of allowed returns in view of the stability of the inflation rate experienced over the last decade.

Q. Dr. Morin, how do you explain this inverse relationship between allowed returns and interest rates?

A. It is transparent from the above graph that allowed risk premiums vary inversely with the levels of interest rates. Regulators have systematically increased the authorized risk premium when interest rates declined, and decreased the authorized risk premium when interest rates increased. In other words, commission-authorized returns tend to moderate the impact of interest rate movements on allowed returns.

This phenomenon has been well documented for a long time. Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992), Maddox, Pippert and Sullivan (1995), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates, rising when rates fell and declining when interest rates rose.[12] [13]

The reason for this inverse relationship is that when interest rates rise, bondholders, whose interest rates are fixed, often suffer a decrease in the market

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[12] Brigham, E.F., Shome, D.K., and Vinson, S. R. "The Risk Premium Approach to Measuring a Utility's Cost of Equity." *Financial Management,* Spring 1985, 33-45. ("BSV") Harris, R.S. "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return." *Financial Management,* Spring 1986, 58-67. Harris, R.S. and Marston, F.C. "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts." *Financial Management,* Summer 1992, 63-70. ("HM") Maddox, F.M., Pippert, D. T., and Sullivan, R.N. "An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry" *Financial Management,* Autumn 1995, 89-95. ("MPS")

[13] It is important not to confuse the risk premium on the overall equity market and the risk premium specific to the utility industry.

value of their bonds, experiencing a capital loss. This item is referred to as interest rate risk. Stockholders, on the other hand, are more concerned with the firm's earning power. In order to avoid interest rate risk in an environment of rising interest rates, investors tend to become more willing to undertake equity investments which, although subject to some fear of loss of earning power, are less sensitive to the fear of interest rate risk. The resulting increase in the supply of funds available for such equity investments causes a downward pressure on the market price for equity. So, generally it is observed that if bondholders' fear of interest rate risk exceeds shareholders' fear of loss of earning power, the risk differential will narrow and hence the risk premium will shrink. This item is particularly true in high inflation environments. Interest rates rise as a result of accelerating inflation, and the interest rate risk of bonds intensifies more than the earnings risk of common stocks, which are partially hedged from the ravages of inflation. This phenomenon has been termed as a "lock-in" premium. Conversely in low interest rate environments when bondholders' interest rate fears subside and shareholders' loss of earning power dominate, the risk differential will widen and hence the risk premium will increase. This event has in fact occurred since 1998.

In short, the empirical evidence from the published academic literature demonstrates that the risk premium varies inversely with the level of interest rates.

Q. Please summarize your risk premium estimates.

A. The table below summarizes the ROE estimates obtained from the two risk premium studies. The average risk premium result is clearly 10.8%, as both estimates are identical.

Risk Premium Method	ROE
Historical	10.8%
Allowed Risk Premium	10.8%

D. DCF Estimates

Q. Please describe the DCF approach to estimating the cost of equity capital.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_o = current stock price

g = expected growth rate of dividends, earnings, stock price, book value

The standard traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, *Regulatory Finance*, and Chapter 8 of my new text, *The New Regulatory Finance*. The standard DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The standard DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. Is the constant growth DCF model applicable under all circumstances?

A. No, it is not, as I discussed earlier in my testimony. For companies in a mature industry, such as the electric utility industry had been until recent years, a constant growth rate is a reasonable assumption. For companies in a more dynamic evolving industry, such as the electric utility business, this assumption may not be reasonable; the dividend growth rate may be expected to converge only over time toward a steady-state long-run level.

Q. How did you estimate HECO's cost of equity with the DCF model?

A. I applied the DCF model to two proxies for the electric utility industry: a group of investment-grade dividend-paying integrated electric utilities and a group consisting of the companies that make up Moody's Electric Utility Index.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_0) and the expected long-term growth (g). The expected dividend D_1 in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. The reason is that current stock price provides a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, the current price reflects the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the current dividend yields reported in the latest edition of Value Line's VLIA software. Basing dividend yields on average results from a large group of companies reduces the concern that idiosyncrasies of individual company stock prices will result in an unrepresentative dividend yield.

Q. How did you estimate the growth component of the DCF model?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's growth forecast as an additional proxy.

Q. Why did you reject the use of historical growth rates in applying the DCF model to electric utilities?

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation for two reasons. First, historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore somewhat redundant.

Second, historical growth rates have little relevance as proxies for future long-term growth at this time. They are downward-biased by the sluggish earnings performance in the last five years, due to the structural transformation of the electric utility industry from a regulated monopoly to a more competitive environment. Several electric utility companies have experienced a negative earnings growth rate. The industry as a whole has experienced very little dividend growth over the past five years.

Columns 3, 4, and 5 of Exhibit HECO-1803 display the historical growth in earnings, dividends, and book value per share over the last five years for the electric utility companies that make up Value Line's Electric Utility composite group. The average historical growth rates in earnings, dividends, and book value for the group are 0.0%, -0.3%, and 2.1% over the past 5 years, respectively. Several companies have experienced a negative earnings growth rate, as evidenced by the numerous historical growth rates reported on the table that are negative.

These anemic historical growth rates are certainly not representative of these companies' long-term earning power, and produce unreasonably low DCF estimates, well outside reasonable limits of probability and common sense. To illustrate, adding the historical growth rates of 0.0%, -0.3%, and 2.1% to the average dividend yield of approximately 4.0% prevailing currently for those same companies, produces preposterous cost of equity estimates of 4.0%, 3.7%, and 6.1%, using earnings, dividends, and book value growth rates, respectively. Of course, these estimates of equity costs are outlandish as they are less than the cost of long-term debt for these companies.

Q. Did you consider any other method of estimating expected growth in the DCF model?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, 'ROE'. That is,

$$g = b \times ROE$$

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

However, I do not generally subscribe to the growth results produced by this particular method for several reasons. First, the sustainable method of predicting growth is only accurate under the assumptions that the return on book equity (ROE) is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Second, and more importantly, the sustainable growth method contains a logic trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Third, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore placed no reliance on this method.

Q. Did you consider projected dividend growth in applying the DCF model?

A. No, not at this time. The reason is that it is widely expected that utilities will continue to lower their dividend payout ratio over the next several years. In other words earnings and dividends are not expected to grow at the same rate in the future.

Whenever the dividend payout ratio is expected to change, the intermediate growth rate in dividends cannot equal the long-term growth rate, because dividend/earnings growth must adjust to the changing payout ratio. The assumptions of constant perpetual growth and constant payout ratio are clearly not met. Thus, the implementation of the standard DCF model is of questionable relevance in this circumstance.

Dividend growth rates are unlikely to provide a meaningful guide to investors' growth expectations for utilities in general. This result is because utilities' dividend policies have become increasing conservative as business risks in the industry have intensified steadily. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in earnings that will support future dividends and share prices.

As a practical matter, there are very few dividend growth forecasts available in sharp contrast to the wide availability of earnings growth forecasts.

Q. Is there any empirical evidence documenting the importance of earnings in evaluating investors' expectations in the investment community?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Zacks Investment, First Call Thompson, MSN Investor, Yahoo Finance, and Multex provide comprehensive compilations of investors' earnings forecasts, to name some. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, which accounts for 65% of the ranking.

Q. Dr. Morin, how did you approach the composition of comparable groups in order to estimate HECO's cost of equity with the DCF method?

A. Because HECO is not publicly traded, the DCF model cannot be applied to HECO and proxies must be used. There are two possible approaches in forming proxy groups of companies.

The first approach is to apply cost of capital estimation techniques to a select group of companies directly comparable in risk to HECO. These companies are chosen by the application of stringent screening criteria to a universe of electric utility stocks in an attempt to identify companies with the same investment risk as HECO. Examples of screening criteria include bond rating, beta risk, size, percentage of revenues from electric utility operations, and common equity ratio. The end result is a small sample of companies with a risk profile similar to that of HECO, provided the screening criteria are defined and applied correctly.

The second approach is to apply cost of capital estimation techniques to a large group of electric utilities representative of the electric utility industry average and then make adjustments to account for any difference in investment risk between the company and the industry average. As explained below, in view of substantial changes in circumstances in the electric utility industry, I have chosen the latter approach.

In the current unstable industry environment, it is important to select relatively large sample sizes representative of the electric utility industry as a whole, as opposed to small sample sizes consisting of a handful of companies. This is because the electric utility industry capital market data is highly unstable at this time. As a result of this instability, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities.

From a statistical standpoint, confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Any distortions introduced by measurement errors in the two DCF components of equity return for individual companies, namely dividend yield and growth are mitigated. Utilizing a large portfolio of companies reduces the chance of either overestimating or underestimating the cost of equity for an individual company. For example, in a large group of companies, positive and negative deviations from the expected growth will tend to cancel out owing to the law of large numbers, provided that the errors are independent[14]. The average growth rate of several companies is less likely to diverge from expected growth than is the estimate of growth for a single firm. More generally, the assumptions of the DCF model are more likely to be fulfilled for a large group of companies than for any single firm or for a small group of companies.

[14] If σ_i^2 represents the average variance of the errors in a group of N companies, and σ_{ij} the average covariance between the errors, then the variance of the error for the group of N companies, σ_N^2 is:

$$\sigma_N^2 = \frac{1}{N}\bar{\sigma}_i^2 + \frac{N-1}{N}\bar{\sigma}_{ij}$$

If the errors are independent, the covariance between them (σ_{ij}) is zero, and the variance of the error for the group is reduced to:

$$\sigma_N^2 = \frac{1}{N}\sigma_i^2$$ As N gets progressively larger, the variance gets smaller and smaller.

Moreover, small samples are subject to measurement error, and in violation of the Central Limit Theorem of statistics[15]. From a statistical standpoint, reliance on robust sample sizes mitigates the impact of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring.

The point of all this is that the use of a handful of companies in a highly fluid and unstable industry produces fragile and statistically unreliable results. A far safer procedure is to employ large sample sizes representative of the industry as a whole and apply subsequent risk adjustments to the extent that the company's risk profile differs from that of the industry average.

Q. Please describe your first proxy group for the electric utility business?

A. As a first proxy for the electric utility business, I examined a group of investment-grade utilities designated as combination gas and electric utilities by AUS Utility Reports and whose utility revenues constitute at least 50% of their total revenues. Companies below investment-grade, that is, companies with a bond rating below Baa3, were eliminated as well as those companies without Value Line coverage. Most of these companies are labeled "vertically integrated" electric utilities by S&P in its analysis of utility business risks, the same as HEI, HECO's parent

[15] The Central Limit Theorem describes the characteristics of the distribution of values we would obtain if we were able to draw an infinite number of random samples of a given size from a given population and we calculated the mean of each sample. The Central Limit Theorem asserts: [1] The mean of the sampling distribution of means is equal to the mean of the population from which the samples were drawn. [2] The variance of the sampling distribution of means is equal to the variance of the population from which the samples were drawn divided by the size of the samples. [3] If the original population is distributed normally, the sampling distribution of means will also be normal. If the original population is not normally distributed, the sampling distribution of means will increasingly approximate a normal distribution as sample size increases.

company. The final sample is shown on Page 1 of Exhibit HECO-1804 and includes electric utility companies engaged in predominantly integrated electric utility activities. These companies on average derive 70% of their revenues from electric utility operations. The same group was discussed earlier in connection with beta estimates and is retained for the DCF analysis.

Q. What DCF results did you obtain for your first group of electric utilities using the Value Line growth projections?

A. For purposes of conducting the DCF analysis, as shown on Page 1 of Exhibit HECO-1804, one company (Public Service Enterprise) was eliminated on account of recent merger negotiations. Value Line's growth projection of 18.5% for Teco Energy was deemed unsustainable and replaced with the analyst growth forecast.

As shown on Column 2 of page 2 of Exhibit HECO-1804, the average long-term growth forecast obtained from Value Line is 5.5% for this group. Adding this growth rate to the average expected dividend yield of 4.0% shown in Column 3 produces an estimate of equity costs of 9.5% for the group. Recognition of flotation costs brings the cost of equity estimate to 9.7%, shown in Column 5.

Q. What DCF results did you obtain using the analysts' consensus growth forecast?

A. From the original sample of 21 companies shown on page 1 of Exhibit HECO-1805, CH Energy, MGE Energy, and UniSource were eliminated as no analysts' growth forecasts were available from Zacks. Public Service Enterprise was eliminated on account of recent merger negotiations. For the remaining 17 companies, using the consensus analysts' earnings growth forecast published by Zacks of 6.4% instead of the Value Line forecast, the cost of equity for the group is 10.5%. Recognition of flotation costs brings the cost of equity estimate to 10.7%, shown in Column 5. This analysis is shown on page 2 of Exhibit HECO-

1805.

Q. What DCF results did you obtain for Moody's electric utilities group?

A. Page 1 of Exhibit HECO-1806 displays the electric utilities that make up Moody's Electric Utility Index. No growth forecast was available for Progress Energy from Value Line. Public Service Enterprise was discarded on account of ongoing merger activity. As shown on Column 2 of page 2 of Exhibit HECO-1806, the average long-term growth forecast obtained from Value Line is 6.0% for this group. Coupling this growth rate with the average expected dividend yield of 4.5% shown in Column 3 produces an estimate of equity costs of 10.5% for the group unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 10.8%, shown in Column 5.

Using the consensus analysts' earnings growth forecast of 5.7% from Zacks instead of the Value Line growth forecast, the cost of equity for the Moody's group is 10.1% for the group unadjusted for flotation costs. Adding an allowance for flotation costs to the results brings the cost of equity estimate to 10.4%. This analysis is displayed on Pages 1 and 2 of Exhibit HECO-1807. No growth projections were available for CH Energy and Duquesne Light, and those companies were therefore eliminated from the group. Public Service Enterprise was discarded on account of ongoing merger activity.

Q. Please summarize your DCF estimates.

A. The table below summarizes the DCF estimates. The average of the DCF results is 10.4%.

DCF STUDY	ROE
DCF Integrated Electric Utilities Value Line Growth	9.7%
DCF Integrated Electric Utilities Zacks Growth	10.7%
DCF Moody's Elec Utilities Value Line Growth	10.8%
DCF Moody's Elec Utilities Zacks Growth	10.4%

Q. Do these DCF results understate the cost of equity for HECO?

A. Yes, they do. As discussed at length earlier, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds 1.0, as is the case presently.

E. <u>Need for Flotation Cost Adjustment</u>

Q. Please describe the need for a flotation cost allowance.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. HECO-1809 to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in HECO-1809, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plan, employees' savings plan, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. Is a flotation cost adjustment required for an operating subsidiary like HECO that does not trade publicly?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its ultimate parent, in this case, HEI. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

III. SUMMARY AND RECOMMENDATION ON COST OF EQUITY

Q. Please summarize your results and recommendation.

A. To arrive at my final recommendation, I performed four risk premium analyses.

For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on aggregate historical and allowed risk premium data from the electric utility industry. I also performed DCF analyses on two surrogates for the electric utility industry: a group of investment-grade integrated electric utilities and a group of electric utilities representative of the industry as proxied by Moody's Electric Utility Index. The results from all the various tests are summarized in the table below.

STUDY	ROE
CAPM	11.6%
Empirical CAPM	11.8%
Risk Premium Elec	10.8%
Allowed Risk Premium	10.8%
DCF Integrated Electric Utilities Value Line Growth	9.7%
DCF Integrated Electric Utilities Zacks Growth	10.7%
DCF Moody's Elec Utilities Value Line Growth	10.8%
DCF Moody's Elec Utilities Zacks Growth	10.4%

The average result from the three principal methodologies is as follows:

CAPM	11.7%
Risk Premium	10.8%
DCF	10.4%
AVERAGE	11.0%

The overall average result is 11.0% for the average risk electric utility.

Q. Should the cost of equity estimates be further adjusted to account for HECO being riskier than the average electric utility?

A. Yes. The cost of equity estimates derived from the various comparable groups reflect the risk of the average electric utility. To the extent that these estimates are drawn from a less risky group of companies, the expected equity return applicable to the riskier HECO is downward-biased. In my judgment, a reasonable estimate of the risk differential is on the order of about 25 basis points and I have adjusted my recommendation slightly upward to 11.25% in order to account for HECO's slightly higher relative risks, mainly due to its relatively small size and the presence of debt-equivalent purchased power obligations.

Q. Please comment on HECO's financial risks.

A. Financial risk stems from the method used by the firm to finance its investments and is reflected in its capital structure. It refers to the additional variability imparted to income available to common shareholders by the employment of fixed cost financing, that is, debt capital. Although the use of fixed cost capital (debt and preferred stock) can offer financial advantages through the possibility of leverage of earnings, it creates additional risk due to the fixed contractual obligations associated with such capital. Debt carries fixed charge burdens which must be supported by the company's earnings before any return can be made available to the common shareholder. The greater the percentage of fixed charges to the total income of the company, the greater the financial risk. The use of fixed cost financing introduces additional variability into the pattern of net earnings over and above that already conferred by business risk.

Variations in operating earnings cause amplified variations in equity returns when debt financing is used. The spread in equity returns is wider in the case of debt financing, and the greater the leverage, the greater the spread and the greater the cost of common equity.

Q. Dr. Morin, how do purchased power contracts affect an electric utility's financial risk profile?

A. An electric utility with long-term purchased power contracts possesses higher financial risks than a utility without such contracts, all else remaining constant. A company's obligations pursuant to long-term purchased power contracts are comparable to long-term debt and are treated as such by investors and bond rating agencies. The same is true for leveraged lease arrangements. In an article published in Standard and Poor's The Global Sector Review, dated May 8, 2003, S&P updated its criteria for capital structure treatment of purchased power agreements ("PPA"), noting that industry changes warranted "recognition of a higher debt equivalent when capitalizing PPAs." S&P explained that this more stringent treatment would be factored into its current policy of adjusting the debt/equity ratio of a company for debt equivalents:

> *"The principal capital structure ratio analyzed is total debt to total debt plus equity. However, analyzing debt leverage goes beyond the balance sheet and covers quasi-debt items and elements of hidden financial leverage. Non-capitalized leases, debt guarantees, receivables financing and* ***purchased power contracts are all considered debt equivalents and are reflected as debt in calculating capital structure ratios."***

The risk perceptions of the investment community and bond rating agencies are such that incremental long-term fixed obligations associated with acquiring energy through off-system purchases increase a utility's financial risk. Clearly, if a company's purchased power contract obligations are converted to a debt equivalent, that company's effective debt ratio increases, and so does its risk.

Q. Does financial theory provide a reasonable and consistent method of adjusting for the increased risk and return associated with purchased power contracts?

A. Yes, it does. The cost of equity for a company with substantial purchased power contracts is higher because that company's effective leverage is higher than otherwise would be the case. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing and/or debt equivalents. In other words, the greater the effective debt ratio, the greater the return required by equity investors.

Several researchers have studied the empirical relationship between the cost of capital and effective capital-structure changes. Comprehensive and rigorous empirical studies of the relationship between cost of capital and leverage for public utilities are summarized in Morin, Regulatory Finance, Public Utilities Report, Inc., Arlington, VA, 1994, Chapter 17.

The results of empirical studies and theoretical studies indicate that equity costs increase from as little as 34 to as much as 237 basis points when the debt ratio increases by ten percentage points. The average increase is 138 basis points from the theoretical studies and 76 basis points from the empirical studies, or a range of 7.6 to 13.8 basis points per one percentage point increase in the debt ratio. The more recent studies indicate that the upper end of that range is more indicative of the effect on equity costs.

Q. Can you provide a numerical example of the manner in which debt equivalents increase the cost of equity?

A. Yes, I can. Consider an electric utility with a capital structure consisting of 50% debt capital and 50% common equity capital without any debt equivalents, and whose cost of common equity has been determined to be 11%. For illustrative purposes, let us assume that long-term purchased power contracts raise the company's effective debt ratio from 50% to 55%, indicating a significant increase in financial risk. An upward adjustment to the initial cost of common equity estimate of 11.0% would be required to reflect this additional risk. Since the capital structure difference amounts to 5%, that is, 55% - 50% = 5%, the required upward adjustment to the cost of equity ranges from 7.6 to 13.8 basis points times 5, which equals 38 to 69 basis points. The midpoint of this range is about 55 basis points. Therefore, in this particular example, the initial cost of equity of 11% would have to be adjusted upward by 55 basis points, raising the cost of equity from 11.00% to 11.55%, in order to reflect the weaker effective capital structure engendered by the purchased power contract debt equivalents.

Q. How does the inclusion of purchased power contracts affect HECO's debt ratio?

A. HECO's 2005 year-end capital structure consisted of approximately 47% debt, unadjusted for purchased power contracts. According to Standard & Poor's debt equivalent calculations (see Company witness Sekimura's testimony, HECO T-19, for details), the inclusion of HECO's purchased power contracts as debt equivalent raises HECO's debt ratio from about 47% to approximately 57% a substantial increase that raises the Company's financial risk.

Q. Dr. Morin, did you also consider HECO's small size in arriving at your recommendation?

A. Yes, I did. HECO possesses small revenue and asset bases, both in absolute terms and relative to other utilities. Investment risk increases as company size diminishes, all else remaining constant. The size phenomenon is well documented in the finance literature. Small companies have very different returns than large ones and on average those returns have been higher. The greater risk of small stocks does not fully account for their higher returns over many historical periods. The average small stock premium is well in excess of that of the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks.

In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns.

Q. What is your conclusion with respect to HECO's overall investment risk?

A. The net result of these distinctive risk factors is that HECO possesses slightly above average investment risk relative to U.S. electric utilities. Therefore, I have adjusted the initial cost of equity of 11.0% based on the industry average upward by a conservative 25 basis points, raising the cost of equity from 11.0% to 11.25%. This adjustment reflects the Company's smaller size and weaker than average effective capital structure engendered by the debt-like purchased power contracts, somewhat offset by my assumption of the continuation of the Company's current energy cost adjustment clause in the same manner as in the past which I discuss further in my testimony.

Q. Dr. Morin, what capital structure assumption underlies your recommended return on HECO's common equity capital?

A. My recommended return on common equity for HECO is predicated on the adoption of a test year capital structure consisting of approximately 55% common equity capital unadjusted for purchased power debt equivalents.

Q. Dr. Morin, can you please comment on the impact of the commission's energy cost adjustment clause on the company's business risk and on your recommended return?

A. Yes, certainly. Because of the Company's predominantly oil-based generating capacity, a dominant element of business risk peculiar to HECO is a significant reliance on fuel oil and the potential risks associated with variations in the price of oil. Mitigating this aspect of HECO's business risk is the Commission's continuation of a favorable energy cost adjustment clause, decreasing the

Company's risk of not recovering its substantial fuel costs.

The Energy Cost Adjustment Clause ("ECAC") serves to reimburse HECO for prudently-incurred energy costs in a manner that minimizes the negative financial effects caused by regulatory lag. Consideration of energy costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed. To illustrate, it is my understanding that bond rating agencies would place considerably more weight on the Company's purchased power contracts as debt equivalents in the absence of ECAC, thus weakening the Company's financial integrity. The ECAC mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection is factored into the Company's credit profile as a negative element which in turn raises its cost of capital, as discussed above.

The approval of energy cost recovery mechanisms by regulatory commissions is widespread in the utility business. Approval of fuel adjustment clauses, purchased water adjustment clauses, and purchased gas adjustment clauses has become widespread. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy.

I believe that in the absence of the Commission renewal of the ECAC requested by HECO in this proceeding, not only would HECO's financial condition deteriorate, but its credit ratings would likely be under review for possible downgrade, its customers would be at risk of having to pay higher rates due to access to capital becoming more expensive for HECO, and my recommended return would be significantly higher. This situation would have a substantial negative effect on HECO and its customers because of the magnitude of the energy cost component in its cost of service.

I encourage the Commission to renew HECO's ECAC, and I believe that approval of HECO's request for continued approval of its ECAC is fair to HECO, its customers, and investors. I believe that the ECAC deals with the cost of fuel and purchased energy, as well as with the mix of resources, which can vary month-to-month and which can represent a considerable financial outlay, on a consistent basis, without need for recurring regulatory proceedings that are time-consuming, costly, and, significantly, create uncertainty within the financial community.

Q. Dr. Morin, what is your final conclusion regarding HECO's cost of common equity capital?

A. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of HECO, it is my opinion that a just and reasonable return on the common equity capital of HECO's electric utility operations in the State of Hawaii at this time is 11.25%.

Q. If capital market conditions change significantly between the date of filing your prepared testimony and the date oral testimony is presented, would this cause you to revise your estimated cost of equity?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. Is there a relationship between financial risk and the authorized ROE?

A. There certainly is. The strength of that relationship is amplified for smaller utilities like HECO. A low authorized ROE increases the likelihood the utility will have to rely increasingly on debt financing for its capital needs. This creates the specter of a spiraling cycle that further increases risks to both equity and debt investors; the resulting increase in financing costs is ultimately borne by the utility's customers through higher capital costs and rates of returns.

Q. Is HECO's financial risk impacted by the authorized rate of return on equity?

A. Yes, it is. A low return on equity increases the likelihood that HECO will have to rely on debt financing for its capital needs. As the Company relies more on debt financing, its capital structure becomes more leveraged. Since debt payments are a fixed financial obligation to the utility, this decreases the operating income available for dividend growth. Consequently, equity investors face greater uncertainty about the future dividend potential of the firm. As a result, the company's equity becomes a riskier investment. The risk of default on the Company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the Company will not have access to the capital markets for its outside financing needs, or if so, at prohibitive costs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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(November 2006)

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Robinson College of Business
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RANK: Professor of Finance

HONORS: Professor of Finance for Regulated Industry
Director Center for the Study of Regulated Industry,
College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.
- Master of Business Administration, McGill University, Montreal, Canada, 1969.
- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pa., 1972-3.
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- Associate Professor, University of Montreal School of Business, 1976-1979.
- Distinguished Professor of Finance, Georgia State University, 1979-2006.
- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, College of Business, Georgia State University, 1985-2006.
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986.

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member of the Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Executive Visions Inc., Board of Directors, Member.
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.

PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Ameren

American Water Works Company

Ameritech

Arkansas Western Gas

Baltimore Gas & Electric – Constellation Energy

Bangor Hydro-Electric

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Cascade Natural Gas

Centel

PROFESSIONAL CLIENTS (CONT'D)

Centra Gas

Central Illinois Light & Power Co

Central Telephone

Central & South West Corp.

Chattanoogee Gas Company

Cincinnatti Gas & Electric

Cinergy Corp.

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Natural Gas

Constellation Energy

Delmarva Power & Light Co

Deerpath Group

DTE Energy

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Emera

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

PROFESSIONAL CLIENTS (CONT'D)

Entergy Gulf States, Inc.

Entergy Louisiana, Inc.

Entergy Mississippi Power

Entergy New Orleans, Inc.

First Energy

Florida Water Association

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California - Verizon

GTE Northwest Inc. - Verizon

GTE Service Corp. - Verizon

GTE Southwest Incorporated - Verizon

Gulf Power Company

Havasu Water Inc.

Hawaii Electric Light Company, Inc.

Hawaiian Electric Company, Inc.

Heater Utilities – Aqua - America

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

PROFESSIONAL CLIENTS (CONT'D)

Island Telephone

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

Manitoba Hydro

Maritime Telephone

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Missouri Gas Energy

Mountain Bell

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Tel Enterprises Ltd.

New York Telephone Co.

Norfolk-Southern

Northeast Utilities

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power – Emera Inc.

Nova Scotia Utility and Review Board

NUI Corp.

PROFESSIONAL CLIENTS (CONT'D)

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Pepco Holdings

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Public Service of New Hampshire

Puget Sound Electric Co.

Quebec Telephone

Regie de l'Energie du Quebec

Rochester Telephone

San Diego Gas & Electric

SaskPower

Sierra Pacific Power Company

Southern Bell

Southern States Utilities

Southern Union Gas

South Central Bell

Sun City Water Company

PROFESSIONAL CLIENTS (CONT'D)

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

TXU Corp

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION (CONT'D)

- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2006
  National Seminars:

  Risk and Return on Capital Projects
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Real Options in Utility Capital Investments
  Fundamentals of Utility Finance in a Restructured Environment
  Contemporary Issues in Utility Finance

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Rate of Return

Capital Structure

Generic Cost of Capital

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES

Federal Communications Commission

Federal Energy Regulatory Commission

Georgia Public Service Commission

South Carolina Public Service Commission

North Carolina Utilities Commission

Pennsylvania Public Service Commission

Ontario Telephone Service Commission

Quebec Telephone Service Commission

Newfoundland Board of Commissioners of Public Utilities

Georgia Senate Committee on Regulated Industries

Alberta Public Service Board

Tennessee Regulatory Authority

Oklahoma State Board of Equalization

Mississippi Public Service Commission

Minnesota Public Utilities Commission

Canadian Radio-Television & Telecommunications Comm.

New Brunswick Board of Public Commissioners

Alaska Public Utility Commission

National Energy Board of Canada

Florida Public Service Commission

Montana Public Service Commission

Arizona Corporation Commission

Quebec Natural Gas Board

Quebec Regie de l'Energie

New York Public Service Commission

REGULATORY BODIES (CONT'D)

Washington Utilities & Transportation Commission

Manitoba Board of Public Utilities

New Jersey Board of Public Utilities

Alabama Public Service Commission

Utah Public Service Commission

Nevada Public Service Commission

Louisiana Public Service Commission

Colorado Public Utilities Board

West Virginia Public Service Commission

Ohio Public Utilities Commission

California Public Service Commission

Hawaii Public Utilities Commission

Illinois Commerce Commission

British Columbia Board of Public Utilities

Indiana Utility Regulatory Commission

Minnesota Public Utilities Commission

Texas Public Utility Commission

Michigan Public Service Commission

Iowa Board of Public Utilities

Missouri Public Service Commission

Arkansas Public Service Commission

New Hampshire Public Utility Commission

Delaware Public Utility Commission

Washington Utilities & Transportation Commission

Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC,Docket#R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

Georgia Power, Georgia PSC, Docket # 3397-U, 1983

Georgia Power, Georgia PSC, Docket # 3673-U, 1987

Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

Northern Telephone, Ontario PSC

GTE-Quebec Telephone, Quebec PSC, Docket 84-052B

Newtel., Nfld. Brd of Public Commission PU 11-87

CN-CP Telecommunications, CRTC

Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800

Bell South, FCC generic cost of capital Docket #84-800

American Water Works - Tennessee, Docket #7226

Burlington-Northern - Oklahoma State Board of Taxes

Georgia Power, Georgia PSC, Docket # 3549-U

GTE Service Corp., FCC Docket #84-200

SERVICE AS EXPERT WITNESS (CONT'D)

Mississippi Power Co., Miss. PSC, Docket U-4761

Citizens Utilities, Ariz. Corp. Comm., D # U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, #P-421/CI-86-354

GTE Service Corp., FCC Docket #87-463

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2

Mountain States Bell, Arizona CC, #E-1051-88-146

Georgia Power, Georgia PSC, Docket # 3840-U, 1989

Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

GTE Northwest, Washington UTC, #U-89-3031

Orange & Rockland, New York PSC, Case 89-E-175

Central Illinois Light Company, ICC, Case 90-0127

Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

SERVICE AS EXPERT WITNESS (CONT'D)

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

SERVICE AS EXPERT WITNESS (CONT'D)

Cincinnati Gas & Electric 1994, 1996, 1999, 2004

Southern States Utilities, 1995

CILCO 1995, 1999, 2001

Commonwealth Telephone 1996

Edison International 1996, 1998

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003

Detroit Edison, 1999, 2003

Entergy Gulf States, Texas, 2000, 2004

Hydro Quebec TransEnergie, 2001, 2004

Sierra Pacific Company, 2000, 2001, 2002

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002, 2004

Mississippi Power Company, 2001, 2002

Oklahoma Gas & Electric Company, 2002 -2003

Public Service Electric & Gas, 2001, 2002

NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002

San Diego Gas & Electric, 2002

NB Power, 2002

Entergy New Orleans, 2002

Hydro-Quebec Distribution 2002

SERVICE AS EXPERT WITNESS (CONT'D)

PSI Energy 2003

Fortis – Newfoundland Power & Light 2002

Emera – Nova Scotia Power 2004

Hydro-Quebec TransEnergie 2004

Hawaiian Electric 2004

Missouri Gas Energy 2004

AGL Resources 2004

Arkansas Western Gas 2004

Public Service of New Hampshire 2005

Hawaiian Electric Company 2005

Delmarva Power & Light Company 2005

Union Heat Power & Light 2005

Puget Sound Electric Co 2006-01-16

Cascade Natural Gas 2006

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982

- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982

- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983

- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.

- Committee on New Product Development, FMA, 1985

- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986

- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fla., 1988.

PAPERS PRESENTED

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation

PAPERS PRESENTED (CONT'D)

"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, 1978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research

  Financial Management

  Financial Review

  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. 1982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2004

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2006.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

"An Economic & Financial Profile of the Canadian Cablevision Industry," Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

"Operational Risk Analysis: California Water Utilities," Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company, 1985.

MISCELLANEOUS CONSULTING REPORTS (CONT'D)

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique",CRTC,1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry", International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities", Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

UNIVERSITY SERVICE

- University Senate, elected departmental senator 1987-1989, 1998-2002
- Faculty Affairs Committee, elected departmental representative
- Professional Continuing Education Committee member
- Director Master in Science (Finance) Program
- Course Coordinator, Corporate Finance, MBA program
- Chairman, Corporate Finance Curriculum Committee
- Executive Education: Departmental Coordinator 2000

INTEGRATED ELECTRIC UTILITIES
BETA ESTIMATES

	Company Name	Industry	Beta
1	Alliant Energy	UTILCENT	0.90
2	Ameren Corp.	UTILCENT	0.75
3	CH Energy Group	UTILEAST	0.85
4	Consol. Edison	UTILEAST	0.70
5	DTE Energy	UTILCENT	0.75
6	Energy East Corp.	UTILEAST	0.90
7	Entergy Corp.	UTILCENT	0.85
8	Exelon Corp.	UTILEAST	0.80
9	MGE Energy	UTILCENT	0.75
10	Northeast Utilities	UTILEAST	0.85
11	NSTAR	UTILEAST	0.80
12	Pepco Holdings	UTILEAST	0.85
13	PG&E Corp.	UTILWEST	1.15
14	PNM Resources	UTILWEST	1.00
15	PPL Corp.	UTILEAST	1.00
16	Public Serv. Enterprise	UTILEAST	0.95
17	Puget Energy Inc.	UTILWEST	0.80
18	TECO Energy	UTILEAST	1.05
19	UniSource Energy	UTILWEST	0.75
20	Wisconsin Energy	UTILCENT	0.80
21	Xcel Energy Inc.	UTILWEST	0.90
	AVERAGE		**0.86**

Source: VLIA 10/2006

MOODY'S ELECTRIC UTILITIES
BETA ESTIMATES

	Company Name	Industry	Beta
1	Amer. Elec. Power	UTILCENT	1.25
2	CH Energy Group	UTILEAST	0.85
3	Consol. Edison	UTILEAST	0.70
4	Constellation Energy	UTILEAST	1.00
5	Dominion Resources	UTILEAST	1.00
6	DPL Inc.	UTILCENT	0.95
7	Duquesne Light Hldgs	UTILEAST	0.95
8	Duke Energy	UTILEAST	1.20
9	Energy East Corp.	UTILEAST	0.90
10	Exelon Corp.	UTILEAST	0.80
11	FirstEnergy Corp.	UTILEAST	0.80
12	IDACORP Inc.	UTILWEST	1.00
13	NiSource Inc.	UTILCENT	0.90
14	OGE Energy	UTILCENT	0.75
15	PPL Corp.	UTILEAST	1.00
16	Progress Energy	UTILEAST	0.85
17	Public Serv. Enterprise	UTILEAST	0.95
18	Southern Co.	UTILEAST	0.65
19	TECO Energy	UTILEAST	1.05
20	Xcel Energy Inc.	UTILWEST	0.90
	AVERAGE		**0.92**

Source: VLIA 10/2006

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1931	4.07%	1,000.00				43.23					
1932	3.15%	1,135.75	135.75	40.70	17.64%	39.42	2.22	-8.81%	5.14%	-3.68%	-21.32%
1933	3.36%	969.60	-30.40	31.50	0.11%	28.73	1.75	-27.12%	4.44%	-22.68%	-22.79%
1934	2.93%	1,064.73	64.73	33.60	9.83%	21.06	1.42	-26.70%	4.94%	-21.75%	-31.59%
1935	2.76%	1,025.99	25.99	29.30	5.53%	36.06	1.33	71.23%	6.32%	77.54%	72.01%
1936	2.55%	1,032.74	32.74	27.60	6.03%	41.60	1.78	15.36%	4.94%	20.30%	14.27%
1937	2.73%	972.40	-27.60	25.50	-0.21%	24.24	1.68	-41.73%	4.04%	-37.69%	-37.48%
1938	2.52%	1,032.83	32.83	27.30	6.01%	27.55	1.45	13.66%	5.98%	19.64%	13.62%
1939	2.26%	1,041.65	41.65	25.20	6.68%	28.85	1.51	4.72%	5.48%	10.20%	3.51%
1940	1.94%	1,052.84	52.84	22.60	7.54%	22.22	1.57	-22.98%	5.44%	-17.54%	-25.08%
1941	2.04%	983.64	-16.36	19.40	0.30%	13.45	1.27	-39.47%	5.72%	-33.75%	-34.06%
1942	2.46%	933.97	-66.03	20.40	-4.56%	14.29	1.28	6.25%	9.52%	15.76%	20.33%
1943	2.48%	996.86	-3.14	24.60	2.15%	21.01	1.46	47.03%	10.22%	57.24%	55.10%
1944	2.46%	1,003.14	3.14	24.80	2.79%	21.09	1.35	0.38%	6.43%	6.81%	4.01%
1945	1.99%	1,077.23	77.23	24.60	10.18%	31.14	1.37	47.65%	6.50%	54.15%	43.97%
1946	2.12%	978.90	-21.10	19.90	-0.12%	32.71	1.48	5.04%	4.75%	9.79%	9.91%
1947	2.43%	951.13	-48.87	21.20	-2.77%	25.60	1.58	-21.74%	4.83%	-16.91%	-14.14%
1948	2.37%	1,009.51	9.51	24.30	3.38%	26.20	1.63	2.34%	6.37%	8.71%	5.33%
1949	2.09%	1,045.58	45.58	23.70	6.93%	30.57	1.68	16.68%	6.41%	23.09%	16.16%
1950	2.24%	975.93	-24.07	20.90	-0.32%	30.81	1.85	0.79%	6.05%	6.84%	7.15%
1951	2.69%	930.75	-69.25	22.40	-4.69%	33.85	1.90	9.87%	6.17%	16.03%	20.72%
1952	2.79%	984.75	-15.25	26.90	1.17%	37.85	1.92	11.82%	5.67%	17.49%	16.32%
1953	2.74%	1,007.66	7.66	27.90	3.56%	39.61	2.09	4.65%	5.52%	10.17%	6.62%
1954	2.72%	1,003.07	3.07	27.40	3.05%	47.56	2.14	20.07%	5.40%	25.47%	22.43%
1955	2.95%	965.44	-34.56	27.20	-0.74%	49.35	2.27	3.76%	4.77%	8.54%	9.27%
1956	3.45%	928.19	-71.81	29.50	-4.23%	48.96	2.37	-0.79%	4.80%	4.01%	8.24%
1957	3.23%	1,032.23	32.23	34.50	6.67%	50.30	2.46	2.74%	5.02%	7.76%	1.09%
1958	3.82%	918.01	-81.99	32.30	-4.97%	66.37	2.57	31.95%	5.11%	37.06%	42.03%
1959	4.47%	914.65	-85.35	38.20	-4.71%	65.77	2.64	-0.90%	3.98%	3.07%	7.79%
1960	3.80%	1,093.27	93.27	44.70	13.80%	76.82	2.74	16.80%	4.17%	20.97%	7.17%
1961	4.15%	952.75	-47.25	38.00	-0.92%	99.32	2.86	29.29%	3.72%	33.01%	33.94%
1962	3.95%	1,027.48	27.48	41.50	6.90%	96.49	3.07	-2.85%	3.09%	0.24%	-6.66%
1963	4.17%	970.35	-29.65	39.50	0.99%	102.31	3.33	6.03%	3.45%	9.48%	8.50%
1964	4.23%	991.96	-8.04	41.70	3.37%	115.54	3.68	12.93%	3.60%	16.53%	13.16%

**MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS**

Year	Long-Term Government Bond Yield (1)	20 year Maturity Bond Value (2)	Gain/Loss (3)	Interest (4)	Bond Total Return (5)	Moody's Electric Utility Stock Index (6)	Dividend (7)	Capital Gain/(Loss) % Growth (8)	Yield (9)	Stock Total Return (10)	Equity Risk Premium (11)
1965	4.50%	964.64	-35.36	42.30	0.69%	114.86	4.02	-0.59%	3.48%	2.89%	2.20%
1966	4.55%	993.48	-6.52	45.00	3.85%	105.99	4.18	-7.72%	3.64%	-4.08%	-7.93%
1967	5.56%	879.01	-120.99	45.50	-7.55%	98.19	4.44	-7.36%	4.19%	-3.17%	4.38%
1968	5.98%	951.38	-48.62	55.60	0.70%	104.04	4.58	5.96%	4.66%	10.62%	9.92%
1969	6.87%	904.00	-96.00	59.80	-3.62%	84.62	4.63	-18.67%	4.45%	-14.22%	-10.60%
1970	6.48%	1,043.38	43.38	68.70	11.21%	88.59	4.73	4.69%	5.59%	10.28%	-0.93%
1971	5.97%	1,059.09	59.09	64.80	12.39%	85.56	4.81	-3.42%	5.43%	2.01%	-10.38%
1972	5.99%	997.69	-2.31	59.70	5.74%	83.61	4.92	-2.28%	5.75%	3.47%	-2.27%
1973	7.26%	867.09	-132.91	59.90	-7.30%	60.87	5.04	-27.20%	6.03%	-21.17%	-13.87%
1974	7.60%	965.33	-34.67	72.60	3.79%	41.17	4.83	-32.36%	7.93%	-24.43%	-28.22%
1975	8.05%	955.63	-44.37	76.00	3.16%	55.66	4.99	35.20%	12.12%	47.32%	44.15%
1976	7.21%	1,088.25	88.25	80.50	16.87%	66.29	5.25	19.10%	9.43%	28.53%	11.66%
1977	8.03%	919.03	-80.97	72.10	-0.89%	68.19	5.68	2.87%	8.57%	11.43%	12.32%
1978	8.98%	912.47	-87.53	80.30	-0.72%	59.75	5.98	-12.38%	8.77%	-3.61%	-2.88%
1979	10.12%	902.99	-97.01	89.80	-0.72%	56.41	6.34	-5.59%	10.61%	5.02%	5.74%
1980	11.99%	859.23	-140.77	101.20	-3.96%	54.42	6.67	-3.53%	11.82%	8.30%	12.25%
1981	13.34%	906.45	-93.55	119.90	2.63%	57.20	7.16	5.11%	13.16%	18.27%	15.63%
1982	10.95%	1,192.38	192.38	133.40	32.58%	70.26	7.64	22.83%	13.36%	36.19%	3.61%
1983	11.97%	923.12	-76.88	109.50	3.26%	72.03	8.00	2.52%	11.39%	13.91%	10.64%
1984	11.70%	1,020.70	20.70	119.70	14.04%	80.16	8.37	11.29%	11.62%	22.91%	8.87%
1985	9.56%	1,189.27	189.27	117.00	30.63%	94.98	8.71	18.49%	10.87%	29.35%	-1.27%
1986	7.89%	1,166.63	166.63	95.60	26.22%	113.66	8.97	19.67%	9.44%	29.11%	2.89%
1987	9.20%	881.17	-118.83	78.90	-3.99%	94.24	9.12	-17.09%	8.02%	-9.06%	-5.07%
1988	9.18%	1,001.82	1.82	92.00	9.38%	100.94	8.71	7.11%	9.24%	16.35%	6.97%
1989	8.16%	1,099.75	99.75	91.80	19.16%	122.52	8.85	21.38%	8.77%	30.15%	10.99%
1990	8.44%	973.17	-26.83	81.60	5.48%	117.77	8.76	-3.88%	7.15%	3.27%	-2.20%
1991	7.30%	1,118.94	118.94	84.40	20.33%	144.02	9.02	22.29%	7.66%	29.95%	9.61%
1992	7.26%	1,004.19	4.19	73.00	7.72%	141.06	8.82	-2.06%	6.12%	4.07%	-3.65%
1993	6.54%	1,079.70	79.70	72.60	15.23%	146.70	9.04	4.00%	6.41%	10.41%	-4.82%
1994	7.99%	856.40	-143.60	65.40	-7.82%	115.50	9.01	-21.27%	6.14%	-15.13%	-7.31%
1995	6.03%	1,225.98	225.98	79.90	30.59%	142.90	9.06	23.72%	7.84%	31.57%	0.98%
1996	6.73%	923.67	-76.33	60.30	-1.60%	136.00	9.06	-4.83%	6.34%	1.51%	3.11%
1997	6.02%	1,081.92	81.92	67.30	14.92%	155.73	9.06	14.51%	6.66%	21.17%	6.25%
1998	5.42%	1,072.71	72.71	60.20	13.29%	181.44	8.01	16.51%	5.14%	21.65%	8.36%

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1999	6.82%	848.41	-151.59	54.20	-9.74%	137.30	8.71	-24.33%	4.80%	-19.53%	-9.79%
2000	5.58%	1,148.30	148.30	68.20	21.65%	227.09	8.71	65.40%	6.34%	71.74%	50.09%
2001	5.75%	979.95	-20.05	55.80	3.57%	214.08	8.56	-5.73%	3.77%	-1.96%	-5.54%
Mean											**5.62%**

Source: Mergent's (Moody's) Public Utility Manual 2002 December stock prices and dividends
Dec. Bond yields from Ibbotson Associates 2002 Yearbook Table B-9 Long-Term Government Bonds Yields

ELECTRIC UTILITIES
HISTORICAL GROWTH RATES

	Company Name (1)	Industry (2)	% Earnings Growth 5-Year (3)	% Dividend Growth 5-Year (4)	% Book Value Growth 5-Year (5)
1	Allegheny Energy	UTILEAST			-7.5
2	ALLETE	UTILCENT			
3	Alliant Energy	UTILCENT	-1.0	-12.5	-2.5
4	Amer. Elec. Power	UTILCENT	3.5	-9.0	-3.5
5	Ameren Corp.	UTILCENT	0.5		5.0
6	Aquila Inc.	UTILCENT			-21.5
7	Avista Corp.	UTILWEST	-3.5	-5.0	4.5
8	Black Hills	UTILWEST		3.5	16.0
9	Cen. Vermont Pub. Serv.	UTILEAST	1.0	0.5	2.5
10	CenterPoint Energy	UTILCENT			
11	CH Energy Group	UTILEAST	-1.5		2.0
12	Cleco Corp.	UTILCENT	1.0	2.0	4.0
13	CMS Energy Corp.	UTILCENT	-27.5		-12.5
14	Consol. Edison	UTILEAST	-2.0	1.0	2.5
15	Constellation Energy	UTILEAST	7.5	-7.0	5.5
16	Dominion Resources	UTILEAST	9.0	0.5	3.5
17	DPL Inc.	UTILCENT	-1.0	0.5	-1.0
18	DTE Energy	UTILCENT	-2.0		3.5
19	Duke Energy	UTILEAST	-6.5	0.5	6.0
20	Duquesne Light Hldgs	UTILEAST	-12.0	-8.5	-14.5
21	Edison Int'l	UTILWEST		-9.0	8.5
22	El Paso Electric	UTILWEST	-4.5		8.5
23	Empire Dist. Elec.	UTILCENT	-5.0		2.0
24	Energy East Corp.	UTILEAST	-2.5	5.0	6.0
25	Entergy Corp.	UTILCENT	10.0	7.5	4.5
26	Exelon Corp.	UTILEAST	11.5		4.0
27	FirstEnergy Corp.	UTILEAST		2.5	6.0
28	Florida Public Utilities	UTILEAST	1.0	4.0	9.5
29	Fortis Inc.	UTILEAST	13.5	4.0	9.0
30	FPL Group	UTILEAST	3.5	4.5	6.0
31	G't Plains Energy	UTILCENT	6.0		1.0
32	Green Mountain Pwr.	UTILEAST		5.0	3.0
33	Hawaiian Elec.	UTILWEST	1.0		3.0
34	IDACORP Inc.	UTILWEST	-11.0	-6.0	3.0
35	KFX Inc	UTILCENT			
36	Maine & Maritimes Corp	UTILEAST	-18.0	2.5	5.0

ELECTRIC UTILITIES
HISTORICAL GROWTH RATES

	Company Name	Industry	% Earnings Growth 5-Year	% Dividend Growth 5-Year	% Book Value Growth 5-Year
	(1)	(2)	(3)	(4)	(5)
37	MDU Resources	UTILWEST	12.5	5.0	12.5
38	MGE Energy	UTILCENT	2.0	1.0	6.5
39	NiSource Inc.	UTILCENT		1.0	7.0
40	Northeast Utilities	UTILEAST		30.5	3.0
41	NSTAR	UTILEAST	4.0	1.0	2.0
42	OGE Energy	UTILCENT	-2.0		1.5
43	Otter Tail Corp.	UTILCENT	2.0	2.0	7.5
44	Pepco Holdings	UTILEAST	-1.0		0.5
45	PG&E Corp.	UTILWEST			1.0
46	Pinnacle West Capital	UTILWEST	-5.0	6.5	4.0
47	PNM Resources	UTILWEST	-1.0	5.0	4.5
48	PPL Corp.	UTILEAST	8.5	8.5	12.0
49	Progress Energy	UTILEAST	4.5	3.0	6.5
50	Public Serv. Enterprise	UTILEAST	2.0	0.5	3.5
51	Puget Energy Inc.	UTILWEST	-7.5	-11.5	0.5
52	Rochester Gas & Electric C	UTILEAST			-2.5
53	SCANA Corp.	UTILEAST	7.0	2.0	3.0
54	Sempra Energy	UTILWEST	16.0	-5.0	10.5
55	Sierra Pacific Res.	UTILWEST			-8.0
56	Southern Co.	UTILEAST	2.0	1.0	-1.0
57	TECO Energy	UTILEAST	-20.0	-8.5	-7.5
58	TXU Corp.	UTILCENT	-4.5	-12.0	-24.0
59	U.S. Energy Sys Inc	UTILEAST			5.0
60	UIL Holdings	UTILEAST	-9.0		2.0
61	UniSource Energy	UTILWEST	5.0		12.0
62	UNITIL Corp.	UTILEAST	-1.5		0.5
63	Vectren Corp.	UTILCENT	4.0	3.5	4.5
64	Westar Energy	UTILCENT	-1.5	-14.5	-11.0
65	Wisconsin Energy	UTILCENT	7.5	-11.0	5.0
66	WPS Resources	UTILCENT	11.0	2.0	8.5
67	Xcel Energy Inc.	UTILWEST	-5.5	-11.0	-4.5
	AVERAGE		**0.0**	**-0.3**	**2.1**

Source: Value Line Investment Analyzer 10/2006

INVESTMENT - GRADE INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	Alliant Energy	3.3	4.5
2	Ameren Corp.	4.8	1.5
3	CH Energy Group	4.2	3.0
4	Consol. Edison	5.0	3.0
5	DTE Energy	4.9	3.0
6	Energy East Corp.	4.8	4.0
7	Entergy Corp.	2.7	5.0
8	Exelon Corp.	2.8	7.0
9	MGE Energy	4.3	6.5
10	Northeast Utilities	3.3	6.0
11	NSTAR	3.7	6.0
12	Pepco Holdings	4.3	8.5
13	PG&E Corp.	3.3	5.5
14	PNM Resources	3.2	5.5
15	PPL Corp.	3.5	11.0
16	Public Serv. Enterprise	3.8	3.5
17	Puget Energy Inc.	4.3	5.0
18	TECO Energy	4.8	5.4
19	UniSource Energy	2.6	7.0
20	Wisconsin Energy	2.2	6.5
21	Xcel Energy Inc.	4.3	6.0

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 10/2006

TECO Energy growth projection of 18.5% replaced by analysts' growth forecast of 5.4%.

Public Service Enterprise eliminated from sample due to recent merger negotiations.

INVESTMENT-GRADE INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	3.3	4.5	3.4	7.9	8.1
2	Ameren Corp.	4.8	1.5	4.9	6.4	6.7
3	CH Energy Group	4.2	3.0	4.3	7.3	7.5
4	Consol. Edison	5.0	3.0	5.1	8.1	8.4
5	DTE Energy	4.9	3.0	5.1	8.1	8.3
6	Energy East Corp.	4.8	4.0	5.0	9.0	9.3
7	Entergy Corp.	2.7	5.0	2.8	7.8	8.0
8	Exelon Corp.	2.8	7.0	3.0	10.0	10.2
9	MGE Energy	4.3	6.5	4.6	11.1	11.3
10	Northeast Utilities	3.3	6.0	3.4	9.4	9.6
11	NSTAR	3.7	6.0	4.0	10.0	10.2
12	Pepco Holdings	4.3	8.5	4.7	13.2	13.4
13	PG&E Corp.	3.3	5.5	3.4	8.9	9.1
14	PNM Resources	3.2	5.5	3.4	8.9	9.1
15	PPL Corp.	3.5	11.0	3.8	14.8	15.0
16	Puget Energy Inc.	4.3	5.0	4.5	9.5	9.8
17	TECO Energy	4.8	5.4	5.0	10.4	10.7
18	UniSource Energy	2.6	7.0	2.8	9.8	9.9
19	Wisconsin Energy	2.2	6.5	2.3	8.8	8.9
20	Xcel Energy Inc.	4.3	6.0	4.6	10.6	10.8
	AVERAGE	**3.8**	**5.5**	**4.0**	**9.5**	**9.7**

Notes:

Column 1, 2: Value Line Investment Survey for Windows, 10/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)
1	Alliant Energy	3.3	4.0
2	Ameren Corp.	4.8	6.1
3	CH Energy Group	4.2	
4	Consol. Edison	5.0	3.7
5	DTE Energy	4.9	4.3
6	Energy East Corp.	4.8	4.5
7	Entergy Corp.	2.7	8.3
8	Exelon Corp.	2.8	10.1
9	MGE Energy	4.3	
10	Northeast Utilities	3.3	8.7
11	NSTAR	3.7	5.5
12	Pepco Holdings	4.3	4.8
13	PG&E Corp.	3.3	7.8
14	PNM Resources	3.2	8.3
15	PPL Corp.	3.5	9.2
16	Public Serv. Enterprise	3.8	9.0
17	Puget Energy Inc.	4.3	7.0
18	TECO Energy	4.8	5.4
19	UniSource Energy	2.6	
20	Wisconsin Energy	2.2	7.4
21	Xcel Energy Inc.	4.3	4.3

Notes:
Column 1: Value Line Investment Survey for Windows, 10/2006
Column 2: Zacks long-term earnings growth forecast, 10/2006

CH Energy, MGE Energy, and UniSource were eliminated from sample because no growth forecast was available.

Public Service Enterprise eliminated from sample due to recent merger negotiations.

INVESTMENT-GRADE COMBINATION GAS & ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	3.3	4.0	3.4	7.4	7.6
2	Ameren Corp.	4.8	6.1	5.1	11.2	11.5
3	Consol. Edison	5.0	3.7	5.1	8.8	9.1
4	DTE Energy	4.9	4.3	5.1	9.5	9.7
5	Energy East Corp.	4.8	4.5	5.0	9.5	9.8
6	Entergy Corp.	2.7	8.3	2.9	11.2	11.4
7	Exelon Corp.	2.8	10.1	3.1	13.2	13.3
8	Northeast Utilities	3.3	8.7	3.5	12.2	12.4
9	NSTAR	3.7	5.5	3.9	9.4	9.7
10	Pepco Holdings	4.3	4.8	4.5	9.3	9.6
11	PG&E Corp.	3.3	7.8	3.5	11.3	11.5
12	PNM Resources	3.2	8.3	3.5	11.7	11.9
13	PPL Corp.	3.5	9.2	3.8	13.0	13.2
14	Puget Energy Inc.	4.3	7.0	4.6	11.6	11.9
15	TECO Energy	4.8	5.4	5.0	10.4	10.7
16	Wisconsin Energy	2.2	7.4	2.3	9.7	9.8
17	Xcel Energy Inc.	4.3	4.3	4.5	8.8	9.1
	AVERAGE	**3.8**	**6.4**	**4.1**	**10.5**	**10.7**

Notes:
Column 1: Value Line Investment Survey for Windows, 10/2006
Column 2: Zacks long-term earnings growth forecast, 10/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	Amer. Elec. Power	4.4	2.5
2	CH Energy Group	4.4	3.5
3	Consol. Edison	5.2	2.5
4	Constellation Energy	2.7	13.5
5	Dominion Resources	4.0	8.0
6	DPL Inc.	3.6	5.5
7	Duquesne Light Hldgs	5.9	4.0
8	Duke Energy	4.3	8.5
9	Energy East Corp.	4.8	4.0
10	Exelon Corp.	3.1	7.0
11	FirstEnergy Corp.	3.6	8.5
12	IDACORP Inc.	3.7	4.5
13	NiSource Inc.	4.5	3.5
14	OGE Energy	4.5	4.0
15	PPL Corp.	3.7	8.0
16	Progress Energy	5.5	
17	Public Serv. Enterprise	3.5	1.5
18	Southern Co.	4.7	5.0
19	TECO Energy	4.6	8.5
20	Xcel Energy Inc.	4.8	7.5

Notes:
Column 1, 2: Value Line Investment Analyzer, 10/2006

No Value Line growth forecasts available for Progress Energy.

Public Service Enterprise eliminated from sample due to recent merger negotiations.

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	4.4	2.5	4.5	7.0	7.2
2	CH Energy Group	4.4	3.5	4.6	8.1	8.3
3	Consol. Edison	5.2	2.5	5.3	7.8	8.1
4	Constellation Energy	2.7	13.5	3.1	16.6	16.8
5	Dominion Resources	4.0	8.0	4.3	12.3	12.5
6	DPL Inc.	3.6	5.5	3.8	9.3	9.5
7	Duquesne Light Hldgs	5.9	4.0	6.1	10.1	10.5
8	Duke Energy	4.3	8.5	4.7	13.2	13.4
9	Energy East Corp.	4.8	4.0	5.0	9.0	9.3
10	Exelon Corp.	3.1	7.0	3.3	10.3	10.5
11	FirstEnergy Corp.	3.6	8.5	3.9	12.4	12.6
12	IDACORP Inc.	3.7	4.5	3.9	8.4	8.6
13	NiSource Inc.	4.5	3.5	4.6	8.1	8.4
14	OGE Energy	4.5	4.0	4.7	8.7	8.9
15	PPL Corp.	3.7	8.0	4.0	12.0	12.2
16	Southern Co.	4.7	5.0	4.9	9.9	10.2
17	TECO Energy	4.6	8.5	5.0	13.5	13.8
18	Xcel Energy Inc.	4.8	7.5	5.2	12.7	12.9
	AVERAGE	**4.3**	**6.0**	**4.5**	**10.5**	**10.8**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 10/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)
1	Amer. Elec. Power	4.4	3.0
2	CH Energy Group	4.4	
3	Consol. Edison	5.2	4.2
4	Constellation Energy	2.7	11.0
5	Dominion Resources	4.0	9.0
6	DPL Inc.	3.6	7.0
7	Duquesne Light Hldgs	5.9	
8	Duke Energy	4.3	6.0
9	Energy East Corp.	4.8	4.5
10	Exelon Corp.	3.1	9.4
11	FirstEnergy Corp.	3.6	4.8
12	IDACORP Inc.	3.7	4.5
13	NiSource Inc.	4.5	3.4
14	OGE Energy	4.5	3.0
15	PPL Corp.	3.7	8.3
16	Progress Energy	5.5	3.8
17	Public Serv. Enterprise	3.5	7.8
18	Southern Co.	4.7	4.8
19	TECO Energy	4.6	5.7
20	Xcel Energy Inc.	4.8	4.2

Notes:
Column 1: Value Line Investment Analyzer, 10/2006
Column 2: Zacks long-term earnings growth forecast, 10/2006

CH Energy Group and Duquesne Light were eliminated from sample because no growth forecast was available.

Public Service Enterprise eliminated from sample due to recent merger negotiations.

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	4.4	3.0	4.5	7.5	7.7
2	Consol. Edison	5.2	4.2	5.4	9.6	9.9
3	Constellation Energy	2.7	11.0	3.0	14.0	14.2
4	Dominion Resources	4.0	9.0	4.3	13.3	13.5
5	DPL Inc.	3.6	7.0	3.9	10.9	11.1
6	Duke Energy	4.3	6.0	4.6	10.6	10.8
7	Energy East Corp.	4.8	4.5	5.0	9.5	9.8
8	Exelon Corp.	3.1	9.4	3.4	12.8	13.0
9	FirstEnergy Corp.	3.6	4.8	3.8	8.6	8.8
10	IDACORP Inc.	3.7	4.5	3.9	8.4	8.6
11	NiSource Inc.	4.5	3.4	4.6	8.1	8.3
12	OGE Energy	4.5	3.0	4.6	7.6	7.9
13	PPL Corp.	3.7	8.3	4.0	12.3	12.5
14	Progress Energy	5.5	3.8	5.7	9.4	9.7
15	Southern Co.	4.7	4.8	4.9	9.6	9.9
16	TECO Energy	4.6	5.7	4.9	10.6	10.8
17	Xcel Energy Inc.	4.8	4.2	5.0	9.2	9.4
	AVERAGE	**4.2**	**5.7**	**4.4**	**10.1**	**10.4**

Notes:
Column 1: Value Line Investment Analyzer, 10/2006
Column 2: Zacks long-term earnings growth forecast, 10/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

APPENDIX A
CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

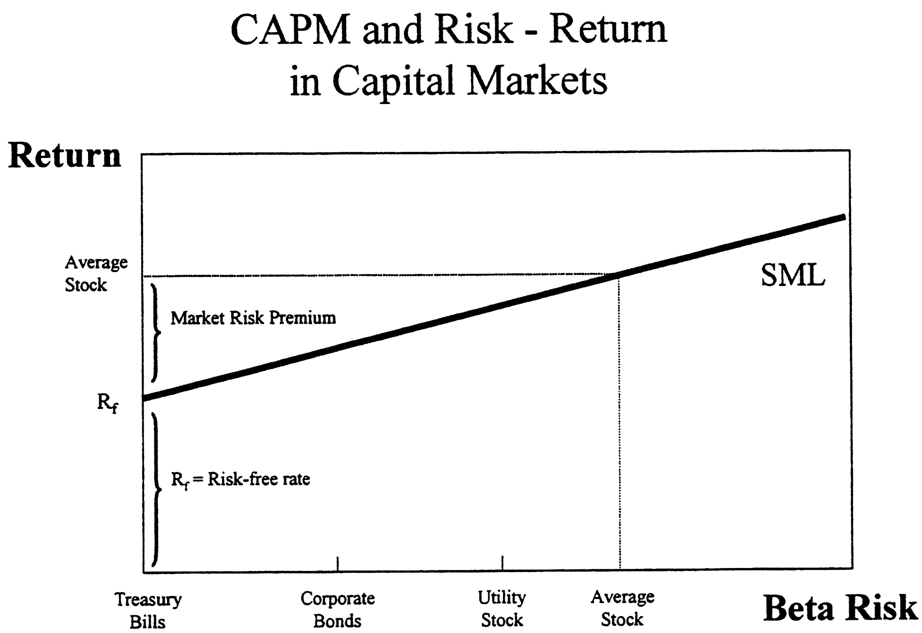
Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is:

$$K = R_F + \beta(R_M - R_F) \qquad (1)$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K, that could be gained on a risk-free investment, R_F, plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, β, and the market risk premium, $(R_M - R_F)$, where R_M is the market return . The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

$$K = R_F + \beta \times MRP \qquad (2)$$

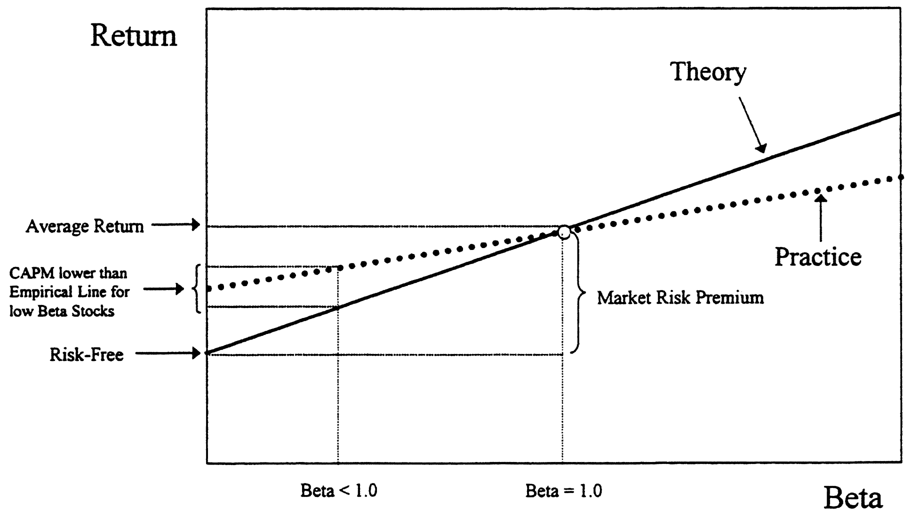
The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Risk vs Return

Theory vs. Practice



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP \qquad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of "alpha" in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979), Litzenberger et al. (1980) and Rosenberg and Marathe (1975) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	**Range of alpha**	**Period relied upon**
Fischer (1993)	-3.6% to 3.6%	1931-1991
Fischer, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien	2.0%	1983-1998

Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1994) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

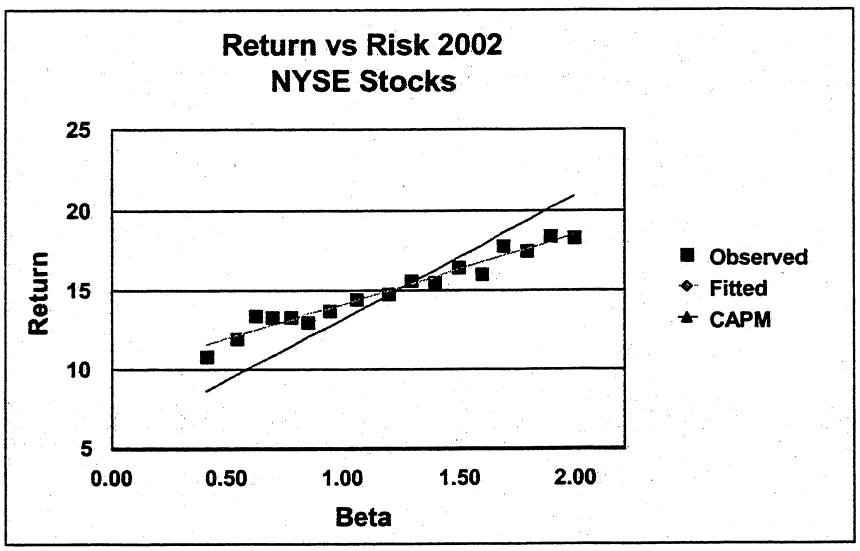
$$K = .0829 + .0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6%, this relationship implies that the intercept of the risk-return relationship is higher than the 6% risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0% in that period, that is, the market risk premium $(R_M - R_F) = 8\%$, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, suggesting an alpha factor of 2%.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table

6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

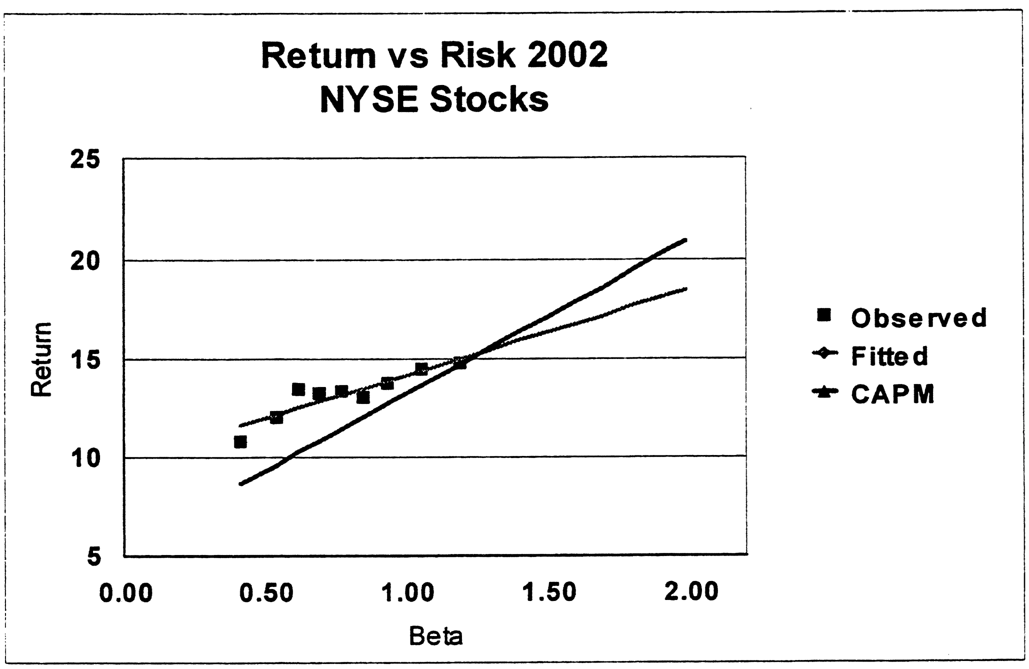
CAPM vs ECAPM



Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return ("TSR") reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	Beta	Return
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7% while the slope is less than equal to the market risk premium of 7.7% predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-

1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year Treasury bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

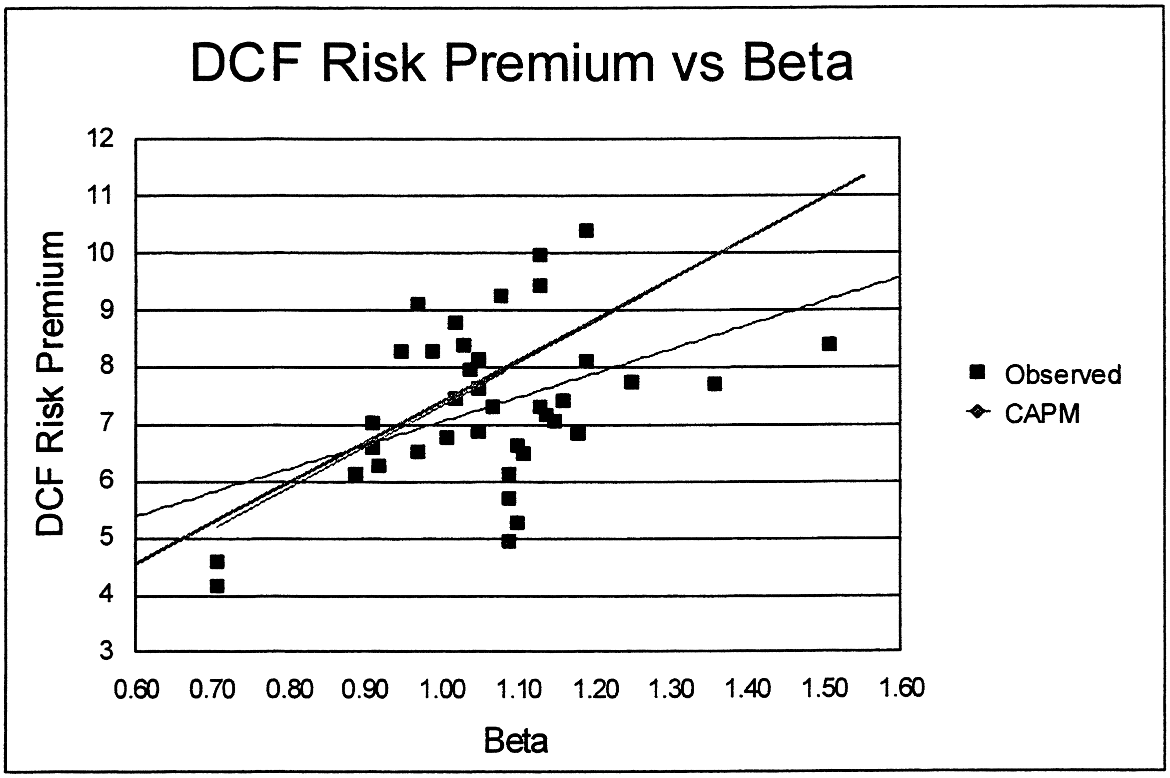
The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

[1] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

Table A-1 Risk Premium and Beta Estimates by Industry

Industry (1)	DCF Risk Premium (2)	Raw Industry Beta (3)	Adjusted Industry Beta (4)
1 Aero	6.63	1.15	1.10
2 Autos	5.29	1.15	1.10
3 Banks	7.16	1.21	1.14
4 Beer	6.60	0.87	0.91
5 BldMat	6.84	1.27	1.18
6 Books	7.64	1.07	1.05
7 Boxes	8.39	1.04	1.03
8 BusSv	8.15	1.07	1.05
9 Chems	6.49	1.16	1.11
10 Chips	8.11	1.28	1.19
11 Clths	7.74	1.37	1.25
12 Cnstr	7.70	1.54	1.36
13 Comps	9.42	1.19	1.13
14 Drugs	8.29	0.99	0.99
15 ElcEq	6.89	1.08	1.05
16 Energy	6.29	0.88	0.92
17 Fin	8.38	1.76	1.51
18 Food	7.02	0.86	0.91
19 Fun	9.98	1.19	1.13
20 Gold	4.59	0.57	0.71
21 Hlth	10.40	1.29	1.19
22 Hsld	6.77	1.02	1.01
23 Insur	7.46	1.03	1.02
24 LabEq	7.31	1.10	1.07
25 Mach	7.32	1.20	1.13
26 Meals	7.98	1.06	1.04
27 MedEq	8.80	1.03	1.02
28 Pap	6.14	1.13	1.09
29 PerSv	9.12	0.95	0.97
30 Retail	9.27	1.12	1.08
31 Rubber	7.06	1.22	1.15
32 Ships	1.95	0.95	0.97
33 Stee	4.96	1.13	1.09
34 Telc	6.12	0.83	0.89
35 Toys	7.42	1.24	1.16
36 Trans	5.70	1.14	1.09
37 Txtls	6.52	0.95	0.97
38 Util	4.15	0.57	0.71
39 Whlsl	8.29	0.92	0.95
MEAN	**7.19**		

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2%, that is approximately equal to 25% of the expected market risk premium of 7.2% shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2%. Instead, the observed slope of close to 5% is approximately equal to 75% of the expected market risk premium of 7.2%, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (5)$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1\text{-}a)\ \beta\ MRP \qquad (6)$$

The empirical findings support values of α from approximately 2% to 7%. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2% - 3% is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM[2]. An alpha in the range of 1% - 2% is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5%, the MRP is 7%, and the alpha factor is 2%. The cost of capital is determined as follows:

$$K = R_F + \alpha + \beta\ (MRP - \alpha)$$
$$K = 5\% + 2\% + 0.80(7\% - 2\%)$$
$$= 11\%$$

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a\,MRP + (1\text{-}a)\ \beta\ MRP$$

[2] The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

With an alpha of 2%, a MRP in the 6% - 8% range, the 'a" coefficient is 0.25, and the ECAPM becomes[3]:

$$K = R_F + 0.25\ MRP + 0.75\ \beta\ MRP$$

Returning to the numerical example, the utility's cost of capital is:

$$K = 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\%$$

$$= 11\%$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical[4].

---

[3] Recall that alpha equals 'a' times MRP, that is, alpha = a MRP, and therefore a = alpha/MRP. If alpha is 2%, then a = 0.25

[4] In the Morin (1994) study, the value of "a" was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520\ \beta$$

The value of a that best explained the observed relationship was 0.25.

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APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%.

In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between $60 and $500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL

(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9.99	13.28%	4.39%
10 - 19.99	8.72	2.76
20 - 39.99	6.93	2.42
40 - 59.99	5.87	1.32
60 - 79.99	5.18	2.34
80 - 99.99	4.73	2.16
100 - 199.99	4.22	2.31
200 - 499.99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1\text{-}f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for \$25, investors expect the firm to pay a dividend of \$2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus k = D/P + g = 2.25/25 + .05 = 14%. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47%.

The initial book value (rate base) is the net proceeds from the stock issue, which are

\$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at \$2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from \$26.25 to \$26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	\$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN =	**14.00%**
(D/P + g)	
ALLOWED RETURN ON EQUITY =	**14.47%**
(D/P(1-f) + g)	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
--------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	5.00%		5.00%	5.00%	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	4.53%		4.53%	4.53%	

TESTIMONY OF
TAYNE S. Y. SEKIMURA

FINANCIAL VICE PRESIDENT

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate of Return on Rate Base

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S. Y. Sekimura and I am the Financial Vice President of Hawaiian Electric Company, Inc. ("HECO" or the "Company"). My business address is 900 Richards Street, Honolulu, Hawaii, 96813. HECO-1900 provides my educational background and work experience.

Q. What is the purpose of your testimony in this proceeding?

A. The primary purpose of my testimony is to recommend a fair and reasonable rate of return on the Company's rate base for test year 2007. I will explain the basis for HECO's capital structure and the derivation of its composite cost of capital. I will provide details supporting the Company's sources, proportions, and costs of investor funds. Further, my testimony will discuss how the Company's Energy Cost Adjustment Clause ("ECAC") addresses the financial factors that Act 162[1] mandates and recommends to the Commission a rate of return on common equity, based on the testimony of Dr. Roger Morin, Professor of Finance, Georgia State University, College of Business, who has developed an estimate of the return on common equity he deems to be fair and reasonable.

Another purpose of my testimony is to explain why the Company does not believe that it is necessary to conduct a comprehensive analysis for this docket of the impact of Hawaiian Electric Industries, Inc. ("HEI") on HECO's cost of capital [in regard to Decision and Order ("D&O") No. 15225[2]].

In addition, my testimony includes an estimate of the savings to customers resulting from the use of special purpose revenue bond financing, as required by Hawaii law.[3]

[1] Section 269-16 (g), Hawaii Revised Statutes.
[2] Decision and Order No. 15225, filed in Docket No. 7591 on December 10, 1996.
[3] Hawaii Revised Statues ("H.R.S.") Section 39-A-208(b).

RATE OF RETURN ON RATE BASE

Q. What is the purpose of the rate of return on rate base?

A. The rate of return on rate base is used to calculate the revenues necessary to fairly compensate investors for the use of their money invested in assets that are used or useful in providing service to the utility's customers.

Q. What is the fair rate of return on rate base for test year 2007?

A. A fair rate of return on rate base for HECO for test year 2007 is 8.92% as calculated on HECO-1901.

Q. Why is 8.92% a fair return on rate base for test year 2007?

A. A rate of return on rate base of 8.92% for HECO is fair because it satisfies the three requirements for fairness established by the Bluefield and Hope cases.

The requirements for "fairness," as set forth in Bluefield Water Works & Improvements Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and in Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944), are that the return should:

1) Be commensurate with returns on investments in other enterprises having corresponding risks and uncertainties;
2) Provide a return sufficient to cover the capital costs of the business, including service on the debt and dividends on the stock; and
3) Provide a return sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and capital-attracting ability.

A return on rate base of 8.92% for HECO for test year 2007 will satisfy these requirements for fairness.

Q. Are these criteria consistent with the criteria used by the Commission in prior rate cases?

A. Yes. These criteria were used by the Commission in numerous HECO rate case decisions including Decision and Order ("D&O") No. 14412 (Docket No. 7766, HECO 1995 Test Year), D&O No. 13762 (Docket No. 7700, HECO 1994 Test Year), and D&O No. 11699 (Docket No. 6998, HECO 1992 Test Year), as well as numerous Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO") rate case decisions.

Q. How should a fair return on rate base be developed in these proceedings?

A. A percentage return on rate base that is at least equal to the Company's composite cost of capital would be a fair rate of return in this docket.

Q. Why must a fair rate of return on rate base be at least equal to HECO's composite cost of capital?

A. The composite cost of capital represents the carrying cost of the money received from investors to finance the rate base. In order to adequately compensate those who have invested in the Company, HECO needs to be allowed a reasonable opportunity to earn at least its composite cost of capital.

Further, a rate of return on rate base at least equal to the Company's composite cost of capital would satisfy the three requirements of a fair return, provided that the Company is given a realistic opportunity to actually earn the return. A finding by the Commission of a return on rate base at least equal to the Company's composite cost of capital would allow the Company to cover the capital costs of the business; it would provide a return on investment commensurate with returns on other investments having corresponding risks; and it would provide assurances to the financial community of the Company's financial integrity (or financial strength).

COMPOSITE COST OF CAPITAL

Q. What is the composite cost of capital?

A. The composite cost of capital is the weighted average cost of short-term debt, long-term debt, hybrid securities, preferred stock, and common equity of the Company. It represents the carrying cost of the money received from investors to finance the rate base.

Q. How is the composite cost of capital calculated?

A. The composite cost of capital is calculated by summing the weighted effective costs of each element of the capital structure. The capital structure is made up of the short-term debt, long-term debt, hybrid securities, preferred stock, and common equity of the Company. The overall cost of each of the elements is calculated taking into account such items as issuance costs to come up with an "effective" cost for each element. The "effective" cost of each element of the capital structure is "weighted" in proportion to its percentage in the capital structure to come up with a weighted effective cost.

Q. Has the same method been used by HECO, HELCO, and MECO in prior rate cases?

A. Yes. This method was used in Docket No. 04-0113 (HECO 2005 Test Year), Docket No. 7766 (HECO 1995 Test Year), Docket No. 7700 (HECO 1994 Test Year), and Docket No. 6998 (HECO 1992 Test Year) as well as numerous HELCO and MECO rate cases.

Q. What is the Company's average estimated composite cost of capital for test year 2007?

A. The Company's estimated average composite cost of capital is 8.92% for test year 2007, as shown on HECO-1901.

GOALS IN FINANCING

Q. What are the Company's overall goals in determining its financing?

A. In determining its financing, the Company strives to balance:

1) obtaining funds at the lowest reasonable cost, and

2) preserving the financial strength of the company.

Obtaining Funds at the Lowest Reasonable Cost

Q. How does the Company obtain funds at the lowest reasonable cost?

A. Low cost funds are obtained by: 1) issuing securities that are relatively low risk to investors and 2) minimizing the Company's business and financial risks, to the extent the Company can control those risks and it is appropriate to do so in the context of the Company's overall business plan.

Q. What securities do investors consider to be relatively low risk?

A. Investors consider debt issuances to be relatively low risk securities since there is assurance that the investor will be paid a stated rate at predetermined periods before other types of investors are able to get disbursements from the Company. Debt is usually the least costly source of funds for the Company.

Q. Why doesn't the Company obtain all its financing from debt?

A. Although debt is low risk to investors, it is relatively high risk to the Company. Higher proportions of debt would mean more fixed obligations and higher risk of default on debt covenants. This would increase the cost of the debt since lenders would need more compensation for taking more risk if there are more fixed obligations. Also, investors will not lend money to companies with no equity support. Some level of equity support is necessary in order to access the debt market. Therefore, the Company must balance the relatively lower cost debt with relatively higher cost equity in determining its capital structure.

Maintaining Financial Strength

Q. Why is it important for the Company to maintain its financial strength?

A. Investors are very sensitive to financial strength considerations when they decide where to invest their money. If HECO's financial strength is not maintained, more risk adverse investors will invest their money elsewhere. This, in turn, will have negative implications for HECO's customers because it will reduce the demand for the Company's securities and will increase its cost of capital. Further, under adverse market conditions, it may be difficult to attract capital. It is imperative from a customer standpoint, therefore, that HECO at least maintain its current financial strength.

Q. How is financial strength measured?

A. One of the principal measures of a company's financial strength is its credit rating. Credit ratings are issued by independent rating agencies, such as Standard and Poor's ("S&P") or Moody's Investors Services ("Moody's"). A credit rating is an impartial opinion of the general creditworthiness of a company (issuer credit rating) or the creditworthiness of a company with respect to a particular security (issue-specific credit rating). Credit rating agencies evaluate the investment risk in commercial paper, secured and unsecured debt, hybrid securities, and preferred stock. The rating for each security reflects the investment risk in that security, given the rating agency's overall evaluation of the financial condition of the company and the particular characteristics of the individual security.

Q. Why is it important for the Company to maintain good credit ratings?

A. It is important to maintain good credit ratings for the following reasons:

1) Maintaining good credit ratings helps to minimize electric rates by lowering the cost of capital to the Company. A credit rating is a measure of credit risk. All other things being equal, a company with less risk will have a lower cost of capital.

2) Maintaining good credit ratings gives the Company the ability to consistently attract new capital on reasonable terms, whatever the current state of the financial markets. The Company raises its capital in a

competitive market. The supply and demand for investors' funds change as economic conditions change. Under ideal conditions, financing is available for most companies. Under adverse economic conditions, however, companies with weaker credit ratings may find it difficult, if not impossible, to raise new capital. A good credit rating assures investors that the company is financially sound, so that they will continue to have an interest in purchasing the company's securities. For example, many companies (including HECO) restrict their investment portfolios to investments in companies that have ratings that are at least "investment grade."[4] Continuous access to capital markets is critical for a capital-intensive company such as HECO that has an obligation to provide utility services.

Q. How do rating agencies determine credit ratings?

A. In order to determine a company's credit rating, the rating agencies evaluate a wide range of qualitative and quantitative factors that affect the company's credit quality. This assessment considers both the business risks and the financial risks of the company.

Business Risks

Q. What things do the rating agencies consider in assessing business risk?

A. Business risk considerations cited in Standard & Poor's article, "Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers" dated September 14, 2006 (provided in Exhibit HECO -1908), include five basic characteristics: regulation, markets, operations, competitiveness, and management.

Q. What business risks does the Company face?

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[4] Standard & Poor's rating of BBB- or higher or Moody's rating of Baa3 or higher. See S&P "Rating Definitions" in Docket No. 04-0113 (HECO 2005 TY Rate Case), Exhibit HECO-2108, pages 1 to 4 filed on November 12, 2004.

A. The Company faces numerous business risks.[5] I will discuss several business risks underlying each of the five basic characteristics which help to define HECO's business profile.

1. REGULATION

Regulation is a critical aspect that underlies a utility's creditworthiness, and decisions by the regulators can profoundly affect financial performance.

1) <u>Energy Cost Adjustment Clause ("ECAC")</u>

For many years, the Company has been allowed the use of an ECAC. The ECAC is an automatic adjustment provision in HECO's rate schedules that allows HECO to automatically increase or decrease rates to reflect changes in the Company's costs of fuel and purchased energy above or below the expense levels included in base charges, without a rate proceeding. In 2006, new legislation[6] required that the Commission evaluate the continued use of ECAC in each rate proceeding in which it was requested by the Company. Our investors are clearly concerned by the legislative action. I will discuss the financial implications of this legislation in greater detail later in my testimony.

2) <u>Renewable Portfolio Standards</u>

The Renewable Portfolio Standards law ("RPS"), as amended by the Legislature in 2004 and in 2006, requires HECO (in aggregate with HELCO and MECO) to obtain certain percentages of sales from renewable electrical energy resources ("RE").[7] Renewable electrical energy resources include

[5] See "Forward-Looking Statements" from HEI and HECO Form 10-Q for the quarterly period ended September 30, 2006 filed as Exhibit HECO-1909.
[6] Act 162 added a provision in HRS 269-16 reiterating the Commission's discretion to evaluate any automatic fuel rate adjustment clause requested by a utility.
[7] Each electric utility company that sells electricity for consumption in the state shall establish a renewable portfolio standard of: 10% by end of 2010, 15% by end of 2015, and 20% by end of 2020. At

electrical energy generated using renewable energy sources, and electrical energy savings brought about by renewable displacement technologies (such as solar water heating) or energy efficiency measures. The law also requires that a study be performed to look at the utility's capability of achieving the standards based on a number of factors including impact on customer rates, utility system reliability and stability, costs and availability of appropriate renewable energy resources and technologies, permitting approval, and impacts on the economy, culture, community, and environment. Further, the law directs the Commission to develop and implement, by December 31, 2007, a utility ratemaking structure to provide incentives that encourage utilities to use cost-effective renewable energy resources (while allowing for deviation if the standards cannot be met in a cost-effective manner, or due to events or circumstances beyond the utility's reasonable control), determine the extent that any proposed utility ratemaking structure would impact utility profit margins, and report findings to the Legislature. Thus, uncertainty regarding how and if the Company will be able to finance and recover on its investment in renewable energy resources in order to meet the requirements of the RPS, increases the Company's financial risk.

3) <u>Regulatory Action</u>

The Company has numerous regulatory actions pending before the Commission that will impact the credit rating agency assessment of HECO's regulatory risk. The Company must continue to obtain regulatory rulings that demonstrate regulatory support to at least maintain its current risk level. Regulatory decisions that suggest the utility will not have regulatory support

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least fifty percent of the RPS targets shall be met by electrical energy generated using renewable energy as the source.

increase the Company's risk profile, its cost of capital, and ultimately costs to ratepayers.

The timing and adequacy of rate relief (including timely and adequate interim and final rate relief) affect the business risk of the Company and are matters of concern to the rating agencies. In its credit assessment of HECO dated November 22, 2006[8], S&P stated, "A responsive final rate order from the Hawaii Public Utilities Commission (PUC) with regard to Hawaiian Electric's pending rate case is crucial to help lift key financial measures to more appropriate levels for the ratings."

The PUC issued interim D&O No. 22050 on its 2005 Test Year Rate Case (Docket No. 04-0113) on September 27, 2005, and the Company is still awaiting final decision from the Commission. The outcome of the 2005 Test Year rate case will be a significant indicator of the regulatory environment in which HECO does business. Key considerations include: timely and adequate rate relief, adequate return on equity, recovery of fuel and purchased-power costs, recovery of capital investments, and return on prepaid pension asset. Furthermore, the Company could be required to refund to its customers, with interest, revenues received under interim rate order if and to the extent they exceed the amounts allowed in final rate order. Thus, HECO needs the continuing support of the Commission to help maintain its current credit quality standing. Loss of this support could be detrimental in the rating agencies' assessment of the Company's business risk.

2. MARKETS

Assessing market dynamics begins with an economic and

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[8] See S&P Ratings Direct filed as Exhibit HECO-1910.

demographic evaluation of the service area in which the Company operates.

1) Economy

The Company's operating results are influenced by the volatility of the national and state economy and their impact on the economy of the island of Oahu. Tourism, the largest component of Hawaii's economy, can fluctuate significantly as a result of terrorist acts across the globe, the geopolitical and war situation, and national and international economic conditions. In addition, a large portion of the Company's revenues comes from the large military presence in the state. The impact of having such a large single customer sector is that it potentially creates volatility in the Company's revenues resulting from the nation's decisions with respect to military bases and deployment.

While the economy appears to have rebounded from the effects of the terrorist attacks, a rise in interest rates may slow down the growth in construction and real estate sales activity. Furthermore, the threats of terror attacks have continued to increase the need for physical security of our facilities and the cost of security and insurance.

2) DSM Programs

The Company recognizes the need for and benefit to Hawaii of reducing Hawaii's dependence on fuel oil and central station generation to meet the electricity needs of our customers.

Since 1996, we have implemented energy efficiency demand-side management ("DSM") programs, which have provided incentives to our customers to implement measures that reduce the use of electricity or use electricity more efficiently. Companies incur risks when they encourage customers to reduce the use of their product, which is the case for HECO where DSM Programs are designed to influence the utility customer uses of energy to produce desired changes in demand. The Commission has recognized these risks in the past by allowing for the timely recovery of program costs, lost margins and shareholder incentives. In April 2006, the Commission issued Interim D&O No. 22420 (Docket No. 05-0069) approving HECO's requests to modify its existing DSM programs and implement its proposed interim DSM program. However, the Commission also ordered that HECO's recovery of lost margins and shareholders incentives for its DSM programs be discontinued within 30 days of the Interim D&O (i.e., by May 26, 2006), until further order by the Commission. HECO is assuming continued regulatory support for DSM program costs and some form of alternative DSM utility incentive mechanism, as the Commission addresses issues of whether DSM incentive mechanisms are appropriate to encourage the implementation of DSM programs, and the appropriate mechanism(s) for such DSM incentives, in the Energy Efficiency Docket.

Furthermore, the 2006 Hawaii State Legislature passed energy measures, which were signed into law by the Governor of Hawaii, which gives the Commission the authority, if it deems appropriate, to redirect all or a portion of the funds currently collected by the utilities and included in their revenues through the current utility DSM surcharge into a Public Benefit Fund, for the purpose of supporting customer DSM programs approved by the PUC. If the fund is established, the PUC is required to appoint a fund administrator (other than an electric utility or utility affiliate), to operate and manage the programs established under the fund.

Thus, continued regulatory support for HECO's DSM programs is essential in reducing HECO's financial risk in investing in demand-side programs versus investing in additional supply-side resources.

3. OPERATIONS

When assessing a utility's operations, creditors focus on the Company's ability to provide reliable and safe electric service, the cost to achieve those goals and ability to recover those investments.

1) Capital Investments

The Company is projecting a need for new generation facilities in the next five years due to the increase in our peak forecast and additional investment in the transmission system to improve reliability and to support growth. Construction of generation and transmission facilities will face many challenges due to public sentiment, politics, and permitting requirements. The processes to get all the approvals needed to install these capital additions take many years and therefore put investor funds at risk for extended periods.

Although the Commission's prior approval of construction projects (see Mr. Morikami's discussion in T-16 regarding General Order No. 7) helps to reduce the Company's business risk, it does not eliminate it completely. There have been cases where the Company has had to make substantial commitment of funds prior to Commission approval under paragraph 2.3.(g)(2) of General Order No. 7 in order to maintain the schedule for a project essential to reliable service, since the Company is not interconnected with other utilities and cannot import power as other utilities can.

Being an island environment, Hawaii has no inter-ties to other sources of electricity and must build its own resources to meet its needs. This increases the significance of making investment in capacity and reliability; and underscores the importance of maintaining access to capital markets to have the financial resources to make necessary capital investments. The Company must be able to construct the facilities and to finance them in order to continue to provide reliable electric service.

2) Purchased Power

The Company expects to purchase approximately 40%[9] of its energy from independent power producers ("IPPs"). Purchase power agreements ("PPAs") have been entered into based on the Company's obligations under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), state laws and rules encouraging the purchase of power from non-fossil fuel producers and qualifying facilities under PURPA, and only with the Commission's determination that costs paid under the contracts were reasonable and approval of the contracts. The contracts are obligations that must be paid before shareholders receive any compensation for the use of their funds. HECO investors receive no compensation for the PPAs, but have earnings potential at risk if power purchase costs are not fully recovered in rates (through base rates or the ECAC).

Other than the October 2004 amendments to the Kalaeloa PPA to increase the firm capacity from 180 MW to 208 MW, which have since been approved by the PUC, there have been no major changes to the existing contracts in recent years. However, as discussed later in my testimony under the section titled "Changes in Accounting Treatment," generally accepted accounting principles (e.g. EITF 01-8 and FIN 46R) may impact the financial statement presentation of the contracts. There is uncertainty as

[9] See Exhibit HECO-403.

to what impact the changes in accounting treatment might have on the investment community's view of those contracts. Credit rating agencies also impute debt on the Company's firm purchased power contracts in order to capture the risks associated with these obligations. I will discuss the accounting change and the calculation of the imputed debt later in my testimony.

3) Compliance with Environmental Laws and Regulation

The electric industry faces increasingly stringent environmental laws and regulations which regulate the operation and modification of existing facilities, the construction and operation of new facilities, and the proper cleanup and disposal of hazardous waste and toxic substances. The Company is at risk for the direct cost of compliance as well as the economic consequences of any impact on operations.

4) Competitive Bidding Proceeding

The stated purpose of this proceeding is to evaluate competitive bidding as a mechanism for acquiring or building new generation capacity in Hawaii. On December 8, 2006, the Commission issued a D&O in this proceeding (D&O No. 23121, Docket No. 03-0372) which included a framework to govern competitive bidding. The Company cannot currently predict the ultimate effect of this proceeding on the ability of the electric utilities to acquire or build additional generating capacity in the future and the associated risks and impact on the Company's cost of capital.

4. COMPETITIVENESS

Although competition in the generation sector in Hawaii has been moderated by the scarcity of generation sites, various permitting processes and lack of interconnection to other electric utilities, HECO faces competition from IPPs and customer self-generation, with or without cogeneration.

1) <u>Bypass Risk -- Distributed Generation ("DG"), Self-Generation</u>

Customers today have more access to alternative energy sources (i.e. self-generation, distributed generation), which are causes for concern for the Company. As these technologies become more economically attractive for customers, the customers may reduce their reliance on, and in some cases may disconnect from, the system, which could put the Company at risk of lost revenues and possible stranded assets.

The PUC opened in October 2003, a DG proceeding to determine DG's potential benefits to and impact on Hawaii's electric distribution systems and markets and to develop policies and a framework for DG projects deployed in Hawaii. On January 27, 2006, the PUC issued its D&O in the DG proceeding (D&O No. 22248, Docket No. 03-0371) indicating that its policy is to promote the development of a market structure that assures DG is available at the lowest feasible cost, DG that is economical and reliable has an opportunity to come to fruition and DG that is not cost-effective does not enter the system. The D&O affirmed the Company's ability to procure and operate DG for utility purposes at utility sites, and also indicated the Commission's desire to promote the development of a competitive market for customer-sited DG. The Company is currently evaluating potential DG projects. If a decision is made to pursue a specific project, an application requesting project approval will be filed with the Commission.

5. MANAGEMENT

Evaluating management is of paramount importance to the creditors' analysis because management decisions affect all areas of a company's operations and financial health.

1) Commitment to Credit Quality

The Company recognizes that creditors' assessment of management has an impact on the Company's credit rating. Thus management is committed to maintaining credit quality and strives to keep the financial community abreast of the Company's goals, objectives, and strategies at its meeting with the rating agencies.

Q. Have the Company's business risks changed since its last rate case?

A. Yes. Since the Company's last rate case (HECO 2005 Test Year), the Company's business risks have increased as it faces more risk and uncertainty as a result of the new legislative Act 162 and the outstanding issues regarding the new pension accounting.

Act 162: Energy Cost Adjustment Clause

Q. Has there been any change in investor concerns relating to the Company's fuel and purchase power expenses?

A. Yes. As I mentioned previously, for many years the Company has been allowed the use of an ECAC. The ECAC allows HECO to automatically increase or decrease rates to reflect changes in the Company's costs of fuel and purchased energy above or below the expense levels included in base charges, without a rate proceeding. In 2006, new legislation required that the Commission evaluate the continued use of ECAC in each rate proceeding in which it was requested by the Company. Our investors are clearly concerned by the legislative action. In its credit assessment of HECO dated November 22, 2006[10], S&P stated in part:

> "Of some concern is Hawaii's Act 162, a new law which appears to confirm, in light of the state legislature's interest in

[10] See S&P Ratings Direct filed as Exhibit HECO-1910.

> promoting renewable energy, the PUC's ability to authorize the utility's fuel adjustment clause. Although no parties to the rate case seem to oppose the continuation of the clause, a material change to fuel-adjustment mechanism would harm the company's financial condition and detract from its currently satisfactory business profile."

Q. Please briefly describe the Company's existing ECAC mechanism.

A. The ECAC is an automatic adjustment provision in the utility's rate schedules that allows the utility (through the application of the "ECA factor") to automatically increase or decrease charges to reflect the change in the Company's energy costs of fuel and purchased energy above or below the levels included in the base charges without a rate proceeding. A rate case proceeding determines the base electricity rates into which are embedded test year levels of fuel prices, payment rates for purchased energy and a test year resource mix. The ECAC mechanism, expressed in cents per kilowatt-hour, allows the Company to recover/return costs due to subsequent changes in (1) fuel and purchased energy costs, (2) the resource mix between utility-owned generation, utility-DG and purchased energy, (3) the resource mix among the utility plants, and (4) the resource mix among purchased energy producers. A rate proceeding also establishes a fixed efficiency factor, or sales heat rate, for the utility central station generation, which provides an incentive to operate the units as efficiently as possible. The ECA factor is filed with the Commission monthly and sets the rate adjustment for the subsequent month. See Mr. Hee's discussion in HECO T-9.

Q. Please describe the investor perspective of the Company's existing ECAC mechanism.

A. HECO's investors view the Company's existing ECAC mechanism very favorably because it significantly reduces the risks associated with our business. Dependence on imported fuel oil and the associated fuel price fluctuation are significant risks in our business. The monthly revenue adjustment for fuel and purchased energy price changes results in timely recovery of fuel oil and purchased energy costs, which significantly reduces the business risk profile. Thus, the existing ECAC has a positive credit quality impact.

In its credit assessment of HECO, S&P has in the past cited "an excellent fuel adjustment clause" as strengthening credit quality in part offsetting "reliance on fuel oil", "significant purchased power obligations", and "high prices" which weaken credit quality.

Q. Are there other investor risks associated with fuel and purchase power?

A. Yes. As noted earlier in my testimony, the Company has significant purchase power obligations (e.g., the Company expects to purchase approximately 40% of its energy from IPPs) which are considered in evaluations of our credit. The reliance on purchased power creates debt-like obligations, which are of concern to investors. Further there have been changes in the accounting treatment of the purchase power obligations and there is uncertainty as to how these changes may impact investor views of these obligations. I discuss the impact of purchased power on our credit quality in greater detail later in my testimony.

Second, the Company is exposed to financial variability due to changes in fuel efficiency. In a rate case proceeding, fuel expense is established based on fuel efficiency factors, which are embedded in base electric rates. Mr. Sakuda provides a complete description of the fuel efficiency calculation in HECO T-4. When actual heat rates are lower (better) than the heat rates embedded in base rates, fuel expense is lower and returns to shareholders are higher. When actual heat rates are higher (worse) than the heat rates embedded in base rates, fuel expense is higher and returns to shareholders are lower. This gives management incentive to optimize the generation dispatch and to maintain and operate the company-owned generation to maximize fuel efficiency.

Finally, the Company bears the costs or enjoys the benefits from cost savings resulting from changes in the carrying costs of fuel inventory. The cost of fuel inventory fluctuates as fuel prices fluctuate. Higher fuel prices result in higher inventory cost and higher costs of carrying inventory which reduces returns to shareholders. Conversely, lower fuel prices result in lower inventory cost and lower costs of carrying inventory which contributes to shareholder returns. There is not much near-term management control over these carrying costs since inventory volumes are constrained by operational requirements and inventory price is determined by the indexed fuel prices embedded in long-term fuel purchase contracts. However, since the absolute amounts of inventory carrying costs are relatively small, this risk is not viewed as a significant business risk from an investor's perspective.

Q. How are investors currently compensated for the risks that they take relating to fuel and purchased power?

A. In general, investors are not specifically compensated for the risks they take relating to fuel. Although dependence on imported fuel oil increases business risks, the existing ECAC mechanism significantly mitigates this risk. The risks associated with changes in the fuel inventory carrying costs are generally not significant from an investor's perspective and investors do earn a return on the fuel inventory included in rate base.

Investor risks associated with purchased power are considered in establishing the appropriate rate of return on equity. In HECO T-18, Dr. Morin discusses the need for shareholder compensation resulting from purchased power.

Q. Does the design of the current ECAC mechanism meet the requirements of Act 162?

A. Yes. As discussed by Dr. Makholm (HECO T-21), HECO's current ECAC mechanism does meet the requirements of Act 162. In the following section, I will elaborate on certain provisions of Act 162 relating to the impact of ECAC on investors.

Q. Does the design of the current ECAC mechanism "fairly share the risk of fuel cost changes between the public utility and its customers"?

A. Yes. As discussed by Dr. Makholm in HECO T-21 (and Mr. Hee in HECO T-9) , fuel cost changes include fuel price changes and fuel efficiency changes. Under the existing ECAC, customers generally bear the risk of fuel price changes and shareholders generally bear the risk of fuel efficiency changes. Customer pay less when actual fuel prices decline, and customers pay more when actual fuel prices escalate. In establishing a fair rate of return on equity, the Company's current ECAC is assumed to continue (see HECO T-20). The concept that shareholders do not make any profit from fuel price changes is therefore embedded in the return on equity recommendation. This is "fair" because shareholders do not require compensation for risks that they do not bear.

Q. How is it "fair" that customers bear nearly all the risks and shareholders take minimal risks associated with fuel price changes?

A. It is "fair" because the required rate of return on common equity is relatively lower due to the fact that shareholders take minimal risks associated with fuel price changes. As a result, customers benefit by having lower electric rates that are based on the relatively lower rate of return on common equity.

Q. If customers pay less when actual fuel prices decline, why does the ECAC revenue have a recent history of being positive (i.e. customers pay more than base rates)?

A. The fuel oil prices used to establish base rates set the "base" in determining whether ECAC is positive or negative. Since under the current ECAC customers will bear nearly all the costs associated with fuel price changes, it does not matter what portion of the fuel cost is reflected in base rates and what portion gets reflected in ECAC. In HECO's 2005 Test Year Rate Case (Docket No. 04-0113) the Company, the Consumer Advocate and the DOD were able to agree on fuel price estimates, since ECAC will adjust revenues to reflect the actual cost of fuel.

Also, currently, fuel price is not a driver for determining when a rate case is needed. If base rates are set at a time when fuel prices are relatively low, the ECAC will be positive when fuel prices rise. Conversely, if base rates are set at a time when fuel prices are relatively high, the ECAC will be negative. For example, if HECO had had a rate case based on a 2000 test year and the base rates were established which incorporated the actual fuel price in 2000, the ECAC in 2001 and 2002 would have been negative and the ECAC in 2003 would have been positive.

Q. Does the design of the current ECAC mechanism "preserve, to the extent reasonable possible, the public utility's financial integrity"?

A. Yes. The current ECAC mechanism is a strength in HECO's business risk profile and contributes to the Company's financial integrity. The monthly timeliness of the existing ECAC also minimizes the recovery time period, further reducing investor uncertainty with respect to recovery of fuel costs.

As I mentioned earlier, S&P has often cited the existing ECAC mechanism as a strength in HECO's credit quality assessment. Conversely, the potential to have changes to the existing ECAC has raised concerns with the rating agencies as noted in S&P's credit assessment of HECO dated November 22, 2006 which is provided in Exhibit HECO-1910.

Q. Does the design of the current ECAC mechanism "minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs"?

A. Yes. The current ECAC design virtually eliminates fuel price changes as a consideration as to when a rate case is necessary.

Q. Are there any alternatives to changing the existing ECAC mechanism if the objective is to "smooth" the impact of fuel price changes on electricity bills?

A. Continuation of the existing ECAC is essential to maintaining the financial integrity of the Company; however, the Company recognizes that volatile fuel prices negatively impact our customers and therefore will consider other means of smoothing the impact of the fuel price changes on customers. Dr. Makholm discusses budget billing and fixed rate billing mechanisms in HECO T-21. Mr. Meehan discusses hedging options in HECO T-22.

Q. What would be necessary if any new or modified fuel cost recovery mechanism is implemented in order to "fairly share the risk of fuel cost changes between the public utility and its customers" and to "preserve, to the extent reasonable possible, the public utility's financial integrity"?

A. Any new or modified fuel cost recovery mechanism that results in increasing investors' risks associated with fuel and/or purchased energy would require an increase in investor compensation through a higher cost of capital for bearing the increased risks. Customers would ultimately bear the higher costs for this increase in cost of capital. See Dr. Morin's discussion in HECO T-18.

Q. What are your conclusions with respect to ECAC?

A. The existing ECAC is a significant rate adjusting mechanism which helps HECO to maintain its current standing with investors. Fuel and purchased power costs are a significant portion of HECO's expenses and therefore have tremendous potential financial impact. It is essential that the potential creditor and shareholder implications of any change to ECAC be carefully and thoroughly considered before implementation.

Utility Industry Restructuring

Q. How has the utility industry changed?

A. Deregulation of the electric utility business was implemented in a substantial number of states in the late 1990's. The impact of deregulation was very different in different states. Perhaps the most obvious failure was that of California with its energy shortfalls and the financial deterioration of its two largest electric utilities: the bankruptcy of Pacific Gas and Electric and near insolvency of Southern California Edison.

Based on S&P data shown below, beginning in 2000 and through 2003, the industry saw widespread financial deterioration and tightening of the capital markets. In 2004 and 2005, while more balanced than in previous years, there continued to be more downgrades than upgrades. For the first half of 2006, upgrades totaled nine companies, versus only four downgrades, in stark contrast to the trend in previous years when rating downgrades outpaced upgrades. Although rating upgrades appear to be rebounding, by looking at the total downgrades vs. upgrades over the period from 2000 to the first half of 2006, it appears that Company ratings are still not where they were prior to 2000.

Standard & Poor's Rating Changes[11]

Year	Downgrade	Upgrade	Total	% Downgrade	% Upgrade
2000	65	20	85	76	24
2001	81	29	110	74	26
2002	182	15	197	92	8
2003	139	8	147	95	5
2004	33	18	51	65	35
2005	46	36	82	56	44
1st half 2006	4	9	13	31	69

[11] See S&P articles "U.S. Utility Downside Rating Actions Moderated Significantly in 2004" and "Pace of U.S. Utility Rating Actions Picked Up in 2005; Downgrades Dominate" filed on May 5, 2006 in Docket No. 05-0315 (HELCO 2006 TY Rate Case), Exhibit HELCO-1811 and HELCO-1812; and "Industry Report Card: U.S. Utility Second-Quarter Upgrade Surge Is Strongest In Years" in HECO-1911.

Q. How has the change in the industry impacted HECO?

A. Although HECO did not face the "deregulated" environment that much of the mainland does, the fact that a utility declared bankruptcy changed investors' perception of risk for investor-owned electric utilities and caused much greater and closer scrutiny of utility regulatory environment. Changes in our regulatory environment, such as those inherent in the RPS law, the increased reliance on DSM (but with a re-assessment or even elimination of the risk protection and recognition associated with the existing lost margin and shareholder incentive recovery mechanisms), and consideration of a competitive bidding requirement for new generation, could significantly impact HECO's financial performance.

Throughout the industry, there is increased awareness that historical regulatory stability does not assure current and future regulatory stability. Investors are increasingly sensitive to the risk associated with changes in the way utilities are regulated. Investors want confidence that the regulators' decisions will be consistent and fair.

<u>Scrutiny of and by Credit Rating Agencies</u>

Q. How did the increased scrutiny of credit rating agencies impact HECO?

A. Increased scrutiny of credit rating agencies prompted the credit rating agencies to reassess how they determine credit ratings. Some examples of what HECO saw as changes at the credit rating agencies included: additional assessments of financial arrangements, renewed focus on established criteria for qualitative and quantitative measures used to establish credit ratings, and more stringent adherence to the range of values used in quantified measures.

Q. What was involved in the assessment of financial arrangements?

A. Moody's asked the Company to provide a listing of any "rating triggers"[12] contained in any contract or arrangement and copies of HECO's line of credit agreements. S&P requested liquidity information and requested responses to another survey regarding rating triggers, which needs to be updated annually.

Q. What are some examples of renewed focus on established criteria?

A. As cited in HECO's 2005 Test Year Rate Case (Docket No. 04-0113, T-21 filed on November 12, 2004), in May 2003, S&P published an update of its methodology for evaluating PPAs entitled "'Buy Versus Build': Debt Aspects of Purchased-Power Agreements" (see Docket No. 04-0113, Exhibit HECO-2111, pages 1 to 5), and in 2004, S&P published new guidelines for business risk assessments entitled "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised" (see Docket No. 04-0113, Exhibit HECO-2112, pages 1 to 19). In addition, in 2006, S&P reemphasized their key credit factors in the publication entitled "Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers" (see Exhibit HECO-1908) and requested for comments regarding its methodology for imputing debt to purchased power obligations involving utility companies (see Exhibit HECO-1915).

Q. What are some examples of more stringent adherence to guidelines?

A. S&P required companies to maintain financial ratios within stated criteria.

Changes in Accounting Treatment

Q. What changes in accounting treatment impact HECO?

A. There are three accounting changes that may significantly impact HECO which I will discuss in detail:

[12] A "rating trigger" is when a contract or arrangement includes a provision that is triggered by a certain type of credit rating change.

1) Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension Plans and Other Postretirement Benefits" ("SFAS 158"),

2) Emerging Issues Task Force Issue No. 01-8 "Determining Whether an Arrangement Contains a Lease" ("EITF 01-8"), and

3) Financial Accounting Standards Board Interpretation No. 46 (revised December 2003) "Consolidation of Variable Interest Entities" ("FIN 46R").

Although EITF 01-8 and FIN 46R were issued several years ago, transition provisions for these accounting changes still apply to HECO, therefore I will discuss their potential impacts on HECO.

<u>SFAS 158 – Pensions and Other Postretirement Benefits</u>

Q. What is SFAS 158?

A. SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)", is a recently-issued accounting guidance. SFAS 158 changes the financial statement reporting requirements for defined benefit pension plans and postretirement benefits other than pensions ("OPEB"). As discussed by Ms. Nanbu in HECO T-10, SFAS 158 requires the Company to (1) recognize on its balance sheet, the overfunded or underfunded status of its defined benefit pension plan (based on the difference between the fair value of the plan assets and the projected benefit obligation ("PBO")) and OPEB plan (based on the difference between the fair value of the plan assets and the accumulated postretirement benefit obligation("APBO")), (2) recognize as a component of accumulated other comprehensive income ("AOCI"), net of tax, the actuarial gains and losses and the prior service costs and credits that arise during the period but are not recognized as components of net periodic pension costs, and (3) other provisions.

Q. How will SFAS 158 impact HECO?

A. HECO will be required to implement SFAS 158 by December 31, 2006. Based on projected balances for December 31, 2006, the Company expects it will be required to: (1) recognize a pension liability and OPEB liability; (2) reverse the existing prepaid pension asset and existing OPEB liability, and, (3) reflect charges to AOCI for pension and OPEB (unless HECO is allowed to create a regulatory asset for amounts that otherwise would be charged to AOCI, which I discuss later in my testimony). Ms. Nanbu describes the projected impact of SFAS 158 in detail in HECO T-10.

Q. How was the funded status of the Company's benefit plans viewed by investors prior to the issuance of SFAS 158?

A. Information regarding the funding status of the pension and OPEB plans has been disclosed to investors since the implementation of SFAS 87, "Employers' Accounting for Pensions" (issued in December 1985) and SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions" (issued in December 1990). Prior to the issuance of SFAS 158, S&P indicated in published industry guidance that it made the adjustments to amounts reported in financial reports to reflect the funded status of pension plans.[13] However, in the past, HECO did not see any documentation that S&P applied these adjustments to the balances reported in HECO's financial statements in its analysis of HECO's financial ratios. Although HECO did not specifically address this issue with S&P, it appeared that past regulatory orders supporting the recoverability of pension costs gave S&P sufficient comfort that pension costs are ultimately recoverable in HECO's rates and therefore S&P did not feel that it was necessary to adjust

[13] S&P article, "No Major Shifts in U.S. Utilities' Pension Funding Status", dated June 12, 2006 (see exhibit HECO-1912)

amounts reported on the balance sheet to reflect the underfunded status of HECO's pension plan.

Q. Please discuss the potential impact of a charge to AOCI on the Company's financial ratios and the credit rating agencies' evaluation of the Company.

A. If the Company must recognize a pension liability and charge to AOCI, it would result in an increase in liabilities and decrease in equity. We expect that these changes would negatively impact the funds from operations interest coverage and total debt/total capital ratios. In addition, a charge to AOCI may trigger closer scrutiny of the regulatory support for the Company's pension and OPEB plans.

Q. Has the Company taken measures to avoid the negative implications of an AOCI charge?

A. Yes. As Ms. Nanbu discusses in HECO T-10, under SFAS 87, the Company would have been required to recognize the funded status of its pension plan if the fair value of its pension fund was less than ABO. In 2003, 2004, and 2005, contributions to the pension fund were made primarily to increase the fair value of the pension plan asset to increase the likelihood that it would be sufficient to cover the ABO and reduce the risk of an AOCI charge. (There was no requirement under SFAS 106 to reflect the funded status of OPEB plans on the balance sheet.) Due to the uncertainty surrounding the possibility of an AOCI charge at the end of 2005, HECO, HELCO. and MECO (together, the "Companies") filed a PUC application, "For Approval to Record a Regulatory Asset for Any Pension Liability Which Would Otherwise Be Charged to Accumulated Other Comprehensive Income" ("AOCI Application") (Docket No. 05-0310) on December 8, 2005. The AOCI Application requested Commission approval to record as a regulatory asset pursuant to SFAS No. 71, "Accounting for the Effects of Certain Regulations," the amount that would otherwise be charged to equity.

The fair value of the pension fund was greater than ABO at December 31, 2005; therefore, there was no charge to AOCI required under SFAS 87 at December 31, 2005.

Under SFAS 158, the Company will be required to recognize the funded status of its pension plan if the fair value of its pension fund is less than PBO. In addition, SFAS 158 requires that the Company must recognize the funded status of its OPEB plans if the fair value of its OPEB fund is less than APBO. The Company determined that it would not be prudent to make the large fund contributions that would be necessary to avert the AOCI charges required under SFAS 158. The Company determined that a more reasonable course would be to continue to pursue Commission approval to create a regulatory asset for the amounts that would otherwise be charged to AOCI. Thus, the Company filed a letter with the Commission on November 17, 2006 to explain that the Company would now be requesting regulatory asset treatment of the amount that would otherwise be charged to equity as required under the provisions of SFAS No. 158. Under the original application, the Company anticipated a potential charge to AOCI for pension only. Under SFAS 158, the Company now anticipates charges to AOCI for both pension and OPEB. The Company anticipates amending its AOCI Application to include regulatory asset treatment for amounts charged to AOCI for OPEB. The request will exclude the executive life portion of OPEB which is not included for ratemaking purposes, which I discuss later in my testimony.

Q. How would the creation of a regulatory asset be viewed by investors?

A. The creation of a regulatory asset in lieu of a change to AOCI will restore equity balances which will improve financial ratios. Further, we expect that approval of the regulatory asset treatment will be viewed favorably by analysts and investors as regulatory support for the Company's pension and OPEB plans. If regulatory asset treatment of the AOCI charge is denied, the AOCI charge will negatively impact the Company's financial ratios and the denial may result in a change in rating agency views of the future recovery of the Company's pension and OPEB obligations. Increased uncertainty of the future recovery of the Company's pension and OPEB obligations could result in security rating downgrades and/or difficulty (or greater expense) in obtaining future financing. S&P has indicated that: "If Standard & Poor's is not comfortable with the ultimate recoverability of a [pension funding] shortfall in rates, this will negatively affect the utility's business profile score. Meanwhile, if utilities have booked a regulatory asset, and Standard & Poor's is comfortable with the ultimate recoverability of that regulatory asset, it will positively affect the business profile score."[14]

Q. Why is obtaining PUC approval of the Company's pending AOCI Application so important to the Company and ratepayers?

A. The Company has an obligation to provide electric services to their customers, regardless of the economic conditions. Therefore, it is critical that the Company's financial strength and ability to raise funds in the financial markets is maintained. Any credit rating downgrade or perceived weakness in the Company's credit quality may result in increased financing costs in the future, as potential bond investors would avoid investing in the Company due to perceived "higher risks" for default or may require higher interest rates to compensate for those perceived added risks. If the Companies' cost of capital increases as a result of recording a charge to AOCI, then that would result in higher revenue requirements in future ratemaking proceedings. As Ms. Nanbu discusses in HECO T-10, the creation of

[14] S&P article, "No Major Shifts in U.S. Utilities' Pension Funding Status", dated June 12, 2006 (see exhibit HECO-1912).

a regulatory asset would not change the net benefit amounts included in rate base and therefore would not change the revenue requirements associated with the benefit plans.

Q. How important is the rate base treatment of net pension asset to investors?

A. Rate base treatment of the net pension asset is extremely important to investors as it allows investors the opportunity to earn on invested funds. Note that the net of the pension liability and the pension regulatory asset is exactly the same as the prepaid pension asset that would exist if the recognition of a pension liability was not required. The key point is that cumulative pension fund contributions have exceeded cumulative pension cost recognized and the net cumulative difference between the contributions and costs must be recognized in rate base for investors and ratepayers to be treated equitably.

Q. Are you aware of any recent ratemaking actions directly relating to treatment of pensions?

A. Yes. In July 2006, the Illinois Commerce Commission issued an order in Commonwealth Edison Company's ("ComEd") electric delivery rate increase request.[15] A disallowance of $854 million pension asset from rate base which was an infusion from ComEd's parent, Exelon Corporation, was a significant ruling in that order.

Q. How did the investment community react to this ratemaking action?

A. The day following the order, Moody's downgraded ComEd's unsecured debt. S&P also subsequently downgraded ComEd. Although I cannot speak definitively to the connection between the pension ratemaking actions and the credit rating actions, it appears that the pension asset disallowance contributed negatively to the credit assessment of ComEd.

[15] Illinois Commerce Commission Order dated July 26, 2006 in Docket No. 05-0597.

Q. Please summarize the investor concerns relating to pensions.

A. The key investor concerns in HECO's case are: recovery of current benefit costs; mechanism for recovery of future benefit costs; return on any net investor-provided funds (or reduction in rate base for any non-investor provided funds); rate of return on equity which takes into consideration the business risk of benefit cost recovery; and restored equity balances to reverse the AOCI charge. To the extent that regulatory treatment of benefit costs changes the business risk profile of the Company, it may impact the equity return expectations of the investor.

<u>EITF 01-8 -- Leases</u>

Q. What is EITF 01-8?

A. EITF 01-8 specifies criteria under which service contracts, such as PPAs, are determined to be lease arrangements and subject to the requirements of Statement of Accounting Standards No. 13, "Accounting for Leases". See KPMG publication entitled "Lease Arrangements Have Broadened" in Docket No. 04-0113 (HECO 2005 TY Rate Case), Exhibit HECO-2113, pages 1 to 3, filed on November 12, 2004.

Q. How has EITF 01-8 impacted HECO?

A. EITF 01-8 applies prospectively to arrangements agreed to, modified, or acquired after May 28, 2003[16]. Therefore, EITF 01-8 affects contemplated new arrangements and contemplated modifications to existing arrangements. The major threat to HECO's capital structure is the possibility that a PPA will be deemed an "arrangement containing a lease" and that the lease may be deemed to be a capital lease. Capital leases are considered a form of debt which would result

[16] The consensus in this Issue should be applied to (a) arrangements agreed to or committed to, if earlier, after the beginning of an entity's next reporting period beginning after May 28, 2003, (b) arrangements modified after the beginning of an entity's next reporting period beginning after May 28, 2003, and (c) arrangements acquired in business combinations initiated after the beginning of an entity's next reporting period beginning after May 28, 2003. EITF 01-8 par. 16.

in additional leverage being included in HECO's capital structure.

Of its existing PPAs, the Kalaeloa contract is not considered within the scope of the EITF 01-8 due to its levels of steam sales, and reassessments of the AES Hawaii and H-Power contracts have not been triggered.[17]

FIN 46R -- Consolidation

Q. What is FIN 46R?

A. FIN 46R is an interpretation of Accounting Research Bulletin No. 51, "Consolidated Financial Statements". It changed the criteria used to determine whether and how certain relationships should be reported on consolidated financial statements. The primary objective of FIN 46R is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights. Entities meeting certain specific criteria are deemed "variable interest entities" ("VIE"). If an entity is determined to be a VIE, HECO must determine whether or not HECO is the "primary beneficiary". "Primary beneficiary" is the enterprise that will absorb a majority of the entity's expected losses, if they occur, or receive a majority of the entity's expected residual returns, if they occur, or both. The primary beneficiary must consolidate the VIE. See summary section of FIN 46R in Docket No. 04-0113 (HECO 2005 TY Rate Case), Exhibit HECO-2114, pages 1 to 3, filed on November 12, 2004.

Q. How has FIN 46R impacted HECO?

A. FIN 46R may change the accounting for certain PPAs. In addition, there may be other potential future transactions that are affected by FIN 46R.

[17] A reassessment of whether the arrangement contains a lease after the inception of the arrangement shall be made only if (a) there is a change in the contractual terms, (b) a renewal option is exercised or an extension is agreed to by the parties to the arrangement, (c) there is a change in the determination as to whether or not fulfillment is dependent on specified property, plant, or equipment, or (d) there is a substantial physical change to the specified property, plant, or equipment. EITF 01-8, par.13.

Q. What is the impact of FIN 46R on PPAs?

A. Assessment of the potential impact of FIN 46R on HECO's PPAs is ongoing.

HECO has requested information from the IPPs with whom it has PPAs. Of the three largest IPPs: 1) HPOWER was determined to be excluded from the scope of FIN 46R[18], 2) AES Hawaii has declined to provide information[19], and 3) Kalaeloa was evaluated under FIN 46R and HECO determined that consolidation of the Kalaeloa PPA is not required.

The consolidation of any significant IPP (new or existing) could have a material effect on HECO's consolidated financial statements, including the recognition of a significant amount of assets and liabilities. Furthermore, if such a consolidated IPP were operating at a loss and had insufficient equity, the potential recognition of such losses could be cause for investor concern and thus increasing the Company's business risk.

Summary of Business Risks

Q. How do HECO's business risks impact its capital structure?

A. Increased business risks have increased the pressure to reduce financial risk in order to maintain the Company's credit rating. Since HECO cannot control much of the business risk it faces, HECO must be resolute in controlling its financial risk. The primary means of reducing its financial risk is by increasing or, at minimum, maintaining the proportion of equity in its capital structure.

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[18] FIN 46R specifies that entities deemed "governmental organization" are not within the scope of FIN 46R. H-Power is a governmental organization as defined by FIN 46R.

[19] FIN 46R specifies: "An enterprise with an interest in a variable interest entity or potential variable interest entity created before December 31, 2003, is not required to apply this Interpretation to that entity if the enterprise, after making an exhaustive effort is unable to obtain the information[a] necessary to (1) determine whether the entity is a variable interest entity, (2) determine whether the enterprise is the variable interest entity's primary beneficiary, or (3) perform the accounting required to consolidate the variable interest entity for which it is determined to be the primary beneficiary. [a]This inability to obtain the necessary information is expected to be infrequent, especially if the enterprise participated significantly in the design or redesign of the entity."

Financial Risk

Q. What do rating agencies consider in evaluating financial risk?

A. Financial risk considerations include financial characteristics, financial policy, profitability, capital structure, cash flow protection and financial flexibility.

Q. How do rating agencies measure financial risk?

A. To assess the financial risk of a company, the rating agencies examine a number of measures, including the following[20]:

1) Funds from operations/interest coverage – measure of ability to pay interest from operations.
2) Funds from operations/total debt – measure of ability to pay total debt from operations.
3) Total debt to total capital – measure of the financial leverage used by the company.

Q. What are HECO's projected ratios for the test year?

A. HECO's projected ratios are provided on HECO-1913. The ratios are based on the assumption that the Company receives PUC approval of regulatory asset treatment in its pending AOCI Application which I discussed earlier.

Q. What are the implications of the projected ratios?

A. A comparison of HECO's projected ratios to the financial guidelines applicable to HECO is shown on HECO-1913. Based on a current business profile assignment of "5", without rate relief:

- the funds from operations/interest coverage ratio is indicative of a BB rating (2.3 in BB range of 1.8-2.8),
- the funds from operations/total debt ratio is indicative of a below BB rating (8

[20] See Standard & Poors "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised" dated June 2, 2004 in Docket No. 04-0113 (HECO 2005 TY Rate Case), Exhibit 2112, pages 1 to 19 filed on November 12, 2004.

in which is below BB range of 10-15) and

- the total debt/total capital ratio is indicative of a BBB rating (54 in BBB range of 60-50).

With rate relief:

- the funds from operations/interest coverage ratio is indicative of a A rating (4.1 in A range of 3.8-4.5),
- the funds from operations/total debt ratio is indicative of a BBB rating (18 in BBB range of 15-22) and
- no change to the total debt/total capital ratio which is indicative of a BBB rating (54 in BBB range of 60-50).

Q. How does the Company's capital structure affect its financial risk?

A. Companies that have more debt (less equity) are deemed to have higher financial risk than companies that have less debt (more equity).

Q. What adjustments to debt amounts reported on the Company's financial statements do credit rating agencies make?

A. S&P has indicated that they make adjustments in two areas:

1) <u>Imputed debt for PPAs and operating leases</u>

The credit rating agencies have determined that certain obligations of the Company that are not reported as liabilities on the Company's balance sheet should be reflected as debt in the ratios used to evaluate the Company's risk profile. In order to capture the risks associated with these obligations, the credit rating agencies calculate "imputed debt." In HECO's case, the credit rating agencies impute debt for its firm capacity PPAs and long-term operating lease obligations.

2) <u>Equity credit for hybrid securities</u>

Hybrid securities have certain features that are equity-like. In calculating ratios, S&P treats hybrids as debt, but gives some equity credit for the hybrids. The equity aspects of the hybrids decline over time.

Q. How does S&P calculate the imputed debt for the PPAs?

A. S&P takes the present value of the total fixed payments over the life of the contracts, using the company's average cost of debt as the discount rate (6%) for the present value calculation. It then determines a risk factor to apply to the contract to reflect the riskiness to the utility based on the terms of the contract and assurances of cost recovery. In its credit assessment of HECO dated May 31, 2006[21], S&P assigned a risk factor of 30% to HECO's take-and-pay contracts. The risk factor is applied to the present value of the fixed payments under the contract to calculate the imputed debt:

Risk Factor x Present Value of Fixed Contract Payments = Imputed Debt

S&P is currently reviewing its rating criteria and based on our understanding of S&P's proposed criteria, HECO's risk factor could be increased to 50% because while the Company's purchased energy costs are currently being recovered through ECAC, the capacity payments are recovered in base rates. As noted in S&P's recent publication[22], "Current guidelines for utilities whose capacity payments are recovered in base rates provides for the application of a 50% risk factor to the NPV of the capacity payments." It goes on to state, "To date, where PPA capacity costs were recovered through a fuel adjustment clause (FAC), as compared with base rate recovery, a risk factor of 30% has been generally used in lieu of the 50% risk factor." The article further states, "In those instances where recovery of PPA-related capacity costs is guaranteed by a legislative mechanism, the level of the risk factor will be determined by the timeliness provided by the

[21] See S&P Ratings Direct filed as Exhibit HECO-1914.
[22] See S&P publication dated November 1, 2006, "Request For Comments: Imputing Debt To Purchased Power Obligations" filed as Exhibit HECO-1915.

legislative true-up mechanism. The strength of the mechanism can result in risk factors as low as 0% because legislatively prescribed recovery mechanisms are viewed as providing utilities with a greater level of protection than that provided by regulatory orders."

Q. Is there anything further to add regarding S&P's calculation of imputed debt?

A. S&P also states in the article cited above that, "Standard & Poor's is abandoning the practice of not imputing debt for contracts with terms of three years or less. In addition, to abandoning our historical three-year rule, we are contemplating applying an evergreen mechanism for short-term contracts. Because expiring contracts must be replaced with either debt-financed capacity additions or replacement PPAs for regulated utilities to meet load serving obligations, Standard & Poor's must look beyond the termination of near-term and intermediate-term contracts to approximate the fixed obligations that will succeed the current contracts in evaluating a utility's financial profile." This possible revision to S&P's criteria could result in an increase to HECO's imputed debt for PPAs, since HECO currently calculates imputed debt on its PPAs till the expiration date of the existing contracts, thus, the estimated amount of imputed debt decreases as the years go by.

Q. What is the impact of the imputed debt for the PPAs on HECO's total debt to total capitalization ratio?

A. The imputed debt for HECO's PPAs increases its December 31, 2005 total debt to total capitalization ratio from 47% to 57% as shown on HECO-1913.

Q. Why is it important for the Company to establish and maintain a sound capital structure?

A. Whereas the Company has little control over many of the business risks it faces, the capital structure impact on financial risk is a risk that the Company can largely control.

Q. What are the Company's target capital structure ratios?

A. The Company hopes to manage its capital structure to maintain a ratio of common equity to total capitalization of about 54% for book purposes. This target is assuming the Company receives PUC approval on the pending AOCI Application, which I discussed earlier.

Q. How did the Company establish its capital structure targets?

A. These capital structure targets were established to at least maintain HECO's existing credit ratings. HECO has ongoing discussions and periodic meetings with the credit rating agencies in order to stay informed of investor perceptions of the Company. Feedback from the rating agencies was key in establishing these ratios.

Q. How do these ratios compare to what was allowed by the Commission in HECO's 1995 test year rate case, Docket No. 7766?

A. In D&O 14412, Docket No. 7766, the Commission established rates based on a capital structure of: 5.46% short-term debt, 38.76% long-term debt, 6.98% preferred stock, and 48.81% common equity. The proportion of common equity increased as HECO's business risk has increased. In response to the increase in business risk, HECO has found it necessary for the proportion of equity to increase. On several occasions over the past several years, we have received indications from the rating agencies that lower credit ratings were being considered unless HECO was able to increase its equity in the capital structure.

Q. How do these ratios compare to Interim D&O issued by the Commission on September 27, 2005 in HECO's 2005 Test Year Rate Case (Docket No. 04-0113)?

A. In the Interim D&O 22050, Docket No. 04-0113, the Commission established rates based on a capital structure of: 3.25% short-term debt, 36.81% long-term debt, 2.37% hybrid securities, 1.78% preferred stock, and 55.79% common equity.

Q. How will customers benefit from the increase in equity in HECO's capital structure?

A. Maintaining credit quality will provide continued access to the capital markets to fund capital projects in order to fulfill our obligation to provide electric service. It provides continued assurance of reasonable financing rates, terms and conditions.

SOURCES OF INVESTOR FUNDS

Q. What are the Company's sources of capital funds?

A. The Company has the following sources of capital funds:

1) Short-Term Borrowings,
2) Long-Term Borrowings,
3) Hybrid Securities,
4) Cumulative Preferred Stock, and
5) Common Stock.

Q. Please describe the Company's short-term borrowings.

A. The Company's short-term borrowings are from HELCO, MECO, HEI, or through the issuance of commercial paper. Funds are borrowed from other corporate entities for terms from a few days up to one year. Access to commercial paper markets is generally limited to borrowers that have sufficiently high credit ratings. As I discussed earlier in my testimony, maintaining HECO's credit rating is essential to assure continued access to the commercial paper market.

Q. Please describe the Company's long-term borrowings.

A. The Company's long-term borrowings consist of revenue bonds issued by the State of Hawaii. The proceeds of the revenue bond issuances are loaned to HECO by the State. HECO is obligated to repay the interest and principal of the bonds.

Interest income to revenue bondholders is generally not taxable for Federal and State of Hawaii income tax purposes, therefore investors are willing to accept lower interest rates than taxable investments. Ratepayers benefit through the lower cost source of funds, as will be more fully described later in my testimony when I discuss the revenue bond savings calculations.

Q. Please describe the revenue bond issuance that is reflected in the Company's long-term borrowings for the 2007 Test Year.

A. At the time the estimates were prepared, the Company assumed it would issue $100 million of revenue bonds, at a 5.50% interest rate. An amended application for the approval of the revenue bond financing was filed with the Commission on October 27, 2006, Docket No. 05-0330, and is pending approval. The long-term borrowings for 2007 may be updated later, depending on the status of the proposed financing.

Q. Please describe the Company's hybrid securities.

A. Hybrid securities have some debt-like features and some equity-like features, hence the name "hybrid". HECO's hybrid securities consist of junior subordinated deferrable interest debentures ("QUIDS"). The QUIDS are sold to trusts which exist for the purpose of issuing cumulative quarterly income preferred securities ("QUIPS"). The QUIPS have features similar to the QUIDS and are sold to third parties. An illustration of the transaction is shown in exhibit HECO-2117 of Docket No. 04-0113 (HECO 2005 TY Rate Case) filed on November 12, 2004. QUIDS have a lower after-tax cost than preferred stock because the periodic interest payments are deductible from taxable income, as are interest payments on traditional long-term debt. The equity-like features of the QUIDS are that they are deeply subordinated, have long maturity, and have a feature that permits the deferral of payments for a period of time.

Q. Please describe the Company's cumulative preferred stock.

A. Preferred stock issuances have stated dividend rates and may have sinking fund redemption provisions. Preferred dividends must be paid before dividends to the common shareholder can be paid.

Q. Please describe the Company's common equity.

A. As a wholly-owned subsidiary of HEI, the Company's common equity balance consists of the funds invested by its shareholder as well as income earned by the shareholder, but not distributed to it (retained earnings).

CAPITAL STRUCTURE

Q. How did you estimate the balances of each of the sources of investor funds?

A. We started with the recorded balances as of December 31, 2005, then we estimated changes in 2006 and 2007.

Q. How were the changes estimated?

A. The estimate of changes was derived from the sources and uses of investor funds (e.g., earnings and capital expenditures) and redemptions or new issuances of external financing.

Q. How is HECO's external financing plan determined?

A. The Company's external financing plan is structured to achieve the sound capital structure discussed earlier in my testimony.

Short-Term Borrowing Balance

Q. What is the average short-term borrowing balance for test year 2007?

A. The Company estimates average short-term borrowings of $39 million. The calculation of the average balance is shown on HECO-1902.

Q. How was the average annual short-term debt amount for test year 2007 computed?

A. The average short-term debt amount was computed by averaging the estimated short-term debt balances at the end of 2006 and 2007.

Q. How was the year-end 2006 and 2007 short-term debt balance estimated?

A. We started with the recorded short-term debt balance as of December 31, 2005. An adjustment was made for the estimated change in 2006 to come to an estimated year-end 2006 balance. The estimated year-end 2006 balance was then adjusted for estimated changes in 2007 to come to an estimated year-end 2007 balance.

Long-Term Borrowing Balance

Q. What is the average long-term borrowing balance for test year 2007?

A. The Company forecast average long-term borrowings of $481 million. The detailed list of revenue bond issuances, and other adjustments that constitute the average balance, are shown on HECO-1903.

Q. How was the average annual long-term debt amount for test year 2007 computed?

A. The average long-term debt amount was computed by averaging the net proceeds of long-term debt at the end of 2006 and 2007.

Q. How were the year-end 2006 and 2007 net proceeds of long-term debt balances estimated?

A. We began with the long term debt balance as of December 31, 2005. Based on the expected financing needs of the Company, the terms of the debt currently outstanding and the prevailing interest rates, we anticipate that HECO would have one revenue bond issuance in 2007.

Depending on market factors and other considerations (such as the accounting treatment of the purchase power contracts), HECO may refinance the Series 1996A and 1996B revenue bonds. The first optional redemption date for the 1996B series is December 1, 2006. The 1996A series is currently redeemable.

An application for the approval to refinance the 1996A and 1996B series was filed with the Commission on September 21, 2006, Docket No. 2006-0383.

On December 4, 2006, the Commission issued Decision and Order No. 23100 authorizing the refinancings. On December 14, 2006, the Companies filed a motion for clarification and/or partial reconsideration of D&O 23100. The motion for clarification is pending before the Commission.

We then calculated the net proceeds as of year-end 2006 and 2007. The net proceeds are equal to the face amount, or par value, of the securities, less any unamortized balances of:

1) issuance costs,
2) issuance discounts,
3) revenue bond investment differentials, and
4) redemption costs.

Only "drawndown amounts" are included in the calculation of net proceeds.

Q. What are issuance costs?

A. Issuance costs are costs incurred as a result of selling securities. They include legal costs, insurance costs, printing costs, underwriters' fees, and other miscellaneous costs of issuing the securities, including the issuance cost related to the Company's syndicated credit facility.

Q. What is the syndicated credit facility ("SCF")?

A. The SCF is a single credit agreement with a group of eight lenders that collectively aggregate $175 million in revolving commitments to lend to HECO under the single credit agreement. On August 30, 2006, HECO filed an application with the Commission for approval of the SCF for a five-year term ending March 31, 2011. Commission approval of the five-year SCF will automatically extend HECO's current 364-day SCF ending on March 29, 2007 (see Docket No. 2006-0360). As such, HECO proposes to amortize the SCF issuance costs over a 5-year period (equivalent to the 5-year term of the SCF agreement, subject to Commission approval).

Q. Why are the SCF issuance cost included in determining the net proceeds for long-term debt in the cost of capital calculation?

A. The SCF issuance cost relates to the cost of establishing financing for the Company, thus if the Commission approves the multi-year SCF, the credit facility will be available for the Company to back-up its commercial paper program and borrow over the 5-year period.

Q. What are issuance discounts?

A. Issuing a security at a discount means that it was sold for less than its face value. At maturity, the full face value will be paid to the bondholder. This approach is attractive to certain buyers who are willing to take the security at a lower effective interest rate in order to get the capital appreciation from the discounted price to the par value at maturity.

Q. Why are bonds sometimes sold at a discount?

A. Selling at a discount can sometimes reduce the effective cost of the bonds, including the amortization of the issuance discount.

Q. What are revenue bond investment differentials?

A. The proceeds from revenue bond sales are put in a construction fund administered by a Trustee. "Drawdowns" from the fund are made for qualified projects. The undrawn proceeds left in the construction fund are invested and earn interest income until they are needed to fund projects. At the same time, interest payments must be made to the revenue bond holders for all of the revenue bonds, including those bonds that provided money still in the construction fund. The investment differential is effectively the difference between the earnings and the interest costs of the undrawn proceeds in the construction fund.

Q. What are the possible types of revenue bond investment differentials?

A. Revenue bond investment differentials can result in any of these situations:

1) "net expense", or negative investment differential -- interest income is less than the interest expense associated with the undrawn proceeds;

2) "net income", or positive investment differential -- interest income is more than the interest expense associated with the undrawn proceeds; or

3) No investment differential -- net expense equals net income.

HECO-WP-1903 p. 5 shows details of the revenue bond investment differentials.

Q. What are redemption costs?

A. Redemption costs are incurred as a result of redeeming securities early (before their maturity dates) in order to achieve cost savings by replacing existing securities with less expensive securities. When the Company redeems a security before its maturity date, it is usually required to pay to the holder of the security its par value plus an additional amount called a redemption premium. Redemption costs include redemption premiums and other miscellaneous costs such as legal and trustee fees.

Q. What are "drawndown amounts"?

A. The proceeds from revenue bond sales are put in a construction fund administered by a Trustee. "Drawdowns" from the fund are made for qualified expenditures. "Drawndown amounts" refer to the disbursements from the fund to the Company.

Q. Why are some funds left undrawn?

A. Funds are left in the construction fund when there are no qualified expenditures to support the disbursement from the fund or it is not economic to support the disbursement from the fund with a specific project due to tax consequences.

Q. Why does HECO sometimes sell bonds before it needs the money?

A. HECO sometimes sells the bonds before it needs the money for several reasons:

1) to obtain as much low cost tax-exempt financing as it can before possible

changes in legislation curtail the availability of this form of financing;

2) to secure an allocation of revenue bonds from the limited amount of revenue bond "cap" that the State of Hawaii Department of Budget and Finance receives each year; and

3) to save costs; it generally costs less to do less frequent, larger sales, instead of several smaller sales.

However, HECO would sell bonds only if it is projecting an eventual need for the funds.

Q. Why are the net proceeds used to determine the average balance?

A. We use the net proceeds because the net amount is all the funds from those security sales that provide cash available to be invested in assets.

Hybrid Securities Balance

Q. What is the average hybrid security balance for test year 2007?

A. The Company estimates average hybrid securities of $28 million. The hybrid security issuance that constitutes the average balance is shown on HECO-1904.

Q. How was the average annual hybrid security amount for test year 2007 computed?

A. The average hybrid security amount was computed by averaging the net proceeds of hybrid securities at the end of 2006 and 2007.

Q. How were the year-end 2006 and 2007 net proceeds of hybrid security balances estimated?

A. We began with the balance as of December 31, 2005. HECO does not anticipate any redemptions or new issuances to impact the hybrid securities balance in the remainder of 2006 or in 2007.

We then calculated the net proceeds as of year-end 2006 and 2007. The net proceeds for hybrid securities are equal to the face amount of the QUIDS less the investment in the trust subsidiary, less any unamortized balances of issuance costs and redemption costs.

Preferred Stock Balance

Q. What is the average preferred stock balance for test year 2007?

A. The Company estimates average preferred stock of $21 million. The detailed list of preferred stock issuances and adjustments which constitute the average balance is shown on HECO-1905.

Q. How was the average annual preferred stock amount for test year 2007 computed?

A. The average preferred stock amount was computed by averaging the net proceeds of preferred stock at the end of 2006 and 2007.

Q. How were the year-end 2006 and 2007 net proceeds of preferred stock balances estimated?

A. We began with the December 31, 2005 balances. The Company does not anticipate any new issuances or redemptions of preferred stock between the recorded year-end 2005 through 2006 and 2007. The net proceeds are equal to the face amount, or par value, of the preferred stock, less any unamortized balances of issuance costs. The only change to the balance during that period is the amortization of unamortized costs.

Common Equity Balance

Q. What is the average common equity balance for test year 2007?

A. The Company estimates average common equity of $697 million. The calculation of the average balance is shown on HECO-1906.

Q. How was the average common equity amount for test year 2007 computed?

A. The average common equity amount was computed by averaging the net proceeds of common equity for ratemaking at the end of 2006 and 2007.

Q. How were the year-end 2006 and 2007 net proceeds of common equity balance estimated?

A. We began with the recorded December 31, 2005 common equity balance. The unamortized issuance cost of preferred stock and the accumulated other comprehensive income ("AOCI") adjustment related to the non-qualified pension plans were restored (added back) to the recorded common equity balance. The result is the common equity balance for ratemaking purposes as of December 31, 2005.

We then reflected the activity for 2006 and 2007 for the estimated net changes in accumulated retained earnings and net AOCI adjustments related to executive life insurance. This calculation is shown in HECO-1906.

Restoration of Unamortized Preferred Stock Issuance Costs

Q. Why is an amount of common equity equal to the unamortized preferred stock issuance costs restored to the book common equity balance (included in "Restoration" on HECO-1906)?

A. For financial statement purposes, the unamortized issuance costs of preferred stock are shown as a reduction to common equity. For ratemaking purposes, however, they are shown as a deduction to preferred stock rather than common equity since these costs relate to preferred stock.

Q. Has the Commission used this adjustment in the past in calculating the Company's common equity balance?

A. Yes. In all final Decision and Orders for the Companies' recent rate cases, the Commission used this adjustment to restore common equity.

Charges to Accumulated Other Comprehensive Income

Q. What is AOCI?

A. Generally accepted accounting standards prescribe that certain situations result in charges to common equity, net of income taxes, which are not reflected on the Company's income statement. These charges are made to an equity account entitled "accumulated other comprehensive income."

Q. Has the Company incurred any AOCI charges to equity?

A. Yes, the Company incurred a charge to equity of about $28,000 related to the non-qualified pension plans as of December 31, 2005. However, the Company proposes to eliminate this AOCI charge from common equity for ratemaking purposes since the AOCI charge is a non-cash balance sheet adjustment related to the non-qualified plans, and the expenses for the non-qualified plans are excluded for ratemaking purposes.

Q. Does the Company expect to have an AOCI charge to common equity in 2006 and/or 2007 (the test year)?

A. Yes, the Company expects to have an AOCI charge in 2006 and 2007 related to the executive life insurance portion of the OPEB plan. As I discussed previously, the Company has requested regulatory asset treatment for amounts that would otherwise be charged to AOCI in its AOCI Application. If the Commission does not approve the request in the AOCI Application, the Company expects to have additional AOCI charges to common equity on December 31, 2006 and 2007.

Q. Why is the executive life insurance portion of the OPEB plan excluded from the Company's request for regulatory asset treatment in the AOCI Application?

A. Per prior Commission ruling (D&O No. 14412, filed on December 11, 1995 in Docket No. 7766, HECO's 1995 Test Year Rate Case), "the cost of life insurance policies for utility company's executives should be borne by the company's shareholders and should not be expensed for ratemaking purposes." Thus, the Company is not requesting regulatory asset treatment for the AOCI charge related to the executive life insurance portion of the OPEB plan.

Q. Why is the AOCI charge related to the executive life insurance eliminated in 2006 and 2007 in determining the common equity balance for ratemaking in HECO-

1906?

A. For financial statement purposes, the AOCI charge related to the executive life insurance is estimated to increase common equity balance. However, the Company proposes to exclude the AOCI charge from common equity for ratemaking purposes, since the AOCI charge is a non-cash balance sheet adjustment which shareholders have not provided, and thus should not be allowed a return on the AOCI charge related to the executive life insurance.

Q. If the Commission does not approve the Company's AOCI Application, and the Company has additional AOCI charges to common equity on December 31, 2006 and 2007 for financial statement purposes, how does the Company propose to treat the AOCI charge for ratemaking purposes?

A. If the Company has additional AOCI charges to common equity on December 31, 2006 or 2007 for financial statement purposes, the Company proposes to eliminate the AOCI charge from common equity for ratemaking purposes. Shareholders have invested funds that exclude the deduction for financial statement purposes for AOCI and should be allowed a return on those invested funds, therefore ratemaking cost of capital should be based on the equity balance excluding the deduction for AOCI.

Capital Structure Summary

Q. Ms. Sekimura, please summarize your testimony of capital structure.

A. A capital structure comprised of 3.08% short-term debt, 38.01% long-term debt, 2.18% hybrid securities, 1.63% cumulative preferred stock, and 55.10% common equity is appropriate.

CAPITAL COSTS

Short-Term Borrowings

Q. What is the estimated cost of short-term borrowings for the test year 2007?

A. The cost of short-term borrowings for the test year 2007 is estimated to be 5.0%.

Q. How was the cost of short-term borrowings determined?

A. We began with the most recent Blue Chip Financial Forecast[23] for federal funds which showed quarterly rates for 2007 of: 5.2%, 5.1%, 5.0%, and 4.9%. We calculated an average for 2007 of 5.05%. We increased this federal funds rate by 10 basis points to reflect the typical spread between federal funds rates and HECO's short-term borrowing rate, and thus rounded our estimate to 5.0%.

Long-Term Borrowings

Q. What is the estimated effective cost of long-term borrowings for the test year 2007?

A. The estimated effective cost of long-term borrowings for the test year 2007 is 6.09%.

Q. How was the effective cost of long-term borrowings determined?

A. The effective cost of long-term borrowings was calculated by dividing (a) the total annual requirement for interest and the amortization of unamortized items by (b) the net proceeds received from the sale of the securities. This calculation is shown on HECO-1903.

Q. What makes up the annual requirements?

A. The annual requirements consist of the annual interest expense, the annual amortization of various costs of issuing and carrying the security, and the annual insurance premiums. The average annual requirements for the test year are shown in column (F) of HECO-1903.

Q. What types of amortized costs are included in calculating the annual requirement?

A. Costs associated with financings that are incurred in only specific periods, but result in a benefit during the entire life of the security, are amortized. Amortized

[23] Forecast dated October 1, 2006.

costs include:

1) issuance costs and issuance discounts,
2) revenue bond investment differentials, and
3) redemption costs, unamortized issuance costs for redeemed bonds, and unamortized investment income differential balances for redeemed bonds.

Issuance Costs and Issuance Discounts

Q. Why should ratepayers pay the costs of issuing bonds or issuing them at a discount?

A. It is appropriate for ratepayers to pay for the issuance costs and issuance discounts because the ratepayers get the benefits from these actions.

Revenue Bond Investment Differentials

Q. How is the revenue bond investment differential treated for ratemaking purposes?

A. The treatment of the revenue bond investment differential depends on whether there is net income or net expense.

Q. When there is net income in the revenue bond investment differential, how is it accounted for in the effective cost of long-term debt?

A. When there is net income, there are two possible situations:

1) When net income does not have to be rebated to the IRS, the positive investment differential is amortized, effectively reducing the annual requirements of the bonds.
2) When net income must be rebated to the IRS, the Company's net proceeds available for use would be increased by any net income until it is rebated to the IRS in five years.[24] This was done for the Series 1988 revenue bonds. Since increased net proceeds, for the same annual requirement, means a

[24] Generally, for revenue bonds issued after 1986, the net income must be rebated to the IRS (with some exceptions), with the first rebate payment due five years after the issue.

lower effective cost of the bonds, customers would receive the benefit for the five years that any net income is held by the Company.

Q. When there is net expense in the revenue bond investment differential, how does the revenue bond investment differential affect the annual requirements of the revenue bonds?

A. When there is net expense, investment differentials are generally amortized (in proportion to the drawn funds) over the life of the revenue bonds. This effectively increases the annual requirements of the bonds.

<u>Redemption Costs and Unamortized Costs for Redeemed Bonds</u>

Q. Why should ratepayers pay the costs of redeeming bonds at a premium, unamortized issuance costs for redeemed bonds, and unamortized investment income differential balances for redeemed bonds?

A. It is appropriate for ratepayers to pay for redemption premiums, unamortized issuance costs for redeemed bonds, and unamortized investment income differential balances for redeemed bonds because ratepayers get the benefits from the bond redemption. When HECO pays a premium to refund a high interest rate bond early, the customers benefit from the lower rates of the new issuance.

Q. Has the Commission included these types of costs in determining the effective costs of the Company's securities in prior rate cases?

A. Yes. In all final Decision and Orders for the Companies' recent rate cases, the Commission has included these types of costs in the effective cost calculation.

<u>Hybrid Securities</u>

Q. What is the estimated cost of hybrid securities for the test year 2007?

A. The estimated effective cost of hybrid securities for the test year 2007 is 7.47%.

Q. How was the cost of hybrid securities determined?

A. The effective cost of hybrid securities was calculated by dividing (a) the total annual requirement for interest and the amortization of unamortized items by (b) the net proceeds received from the sale of the securities. This calculation is shown on HECO-1904.

Preferred Stock

Q. What is the estimated cost of preferred stock for the test year 2007?

A. The estimated effective cost of preferred stock for the test year 2007 is 5.51%.

Q. How was the cost of preferred stock determined?

A. The effective cost of preferred stock was calculated by dividing (a) the total annual requirement for interest and the amortization of unamortized items by (b) the net proceeds received from the sale of the securities. This calculation is shown on HECO-1905.

Common Equity

Q. What would be a fair and reasonable rate of return on common stock equity to be used by the Commission in determining the revenue requirements in this docket?

A. In HECO T-18, Dr. Roger Morin, a Professor of Finance and an expert in this area, has determined that in his opinion a fair and reasonable return on common equity for HECO for test year 2007 would be 11.25%. Dr. Morin did a comprehensive analysis before arriving at his judgment on a fair and reasonable return on common equity for HECO.

Q. Do you accept Dr. Morin's conclusion that a fair return on common equity for HECO in this docket is 11.25%?

A. Yes. An allowed rate of return on equity of 11.25% should give the Company an opportunity to earn a fair and reasonable rate of return in the test year, assuming that the Company obtains adequate rate relief by the beginning of the test year.

Q. When was Dr. Morin's appraisal of the fair return on equity ("ROE") for HECO conducted?

A. It was completed in October 2006.

Capital Costs Summary

Q. Ms. Sekimura, please summarize your testimony on costs of capital.

A. The test year estimates of capital costs for the test year of: short-term debt 5.00%, long-term debt 6.09%, hybrid securities 7.47%, cumulative preferred stock 5.51%, and common equity 11.25% are appropriate.

DETAILED ANALYSIS OF HEI IMPACT NOT NEEDED

Q. Has a comprehensive analysis of HEI's impact on the Companies' cost of capital been done before?

A. Yes. Dennis Thomas and Associates, an independent consultant, was hired to assist the Public Utilities Commission in its investigation of the effects of the relationship between HEI and HECO on the operations of HECO and its electric subsidiaries, HELCO and MECO, and their respective ratepayers. In January 1995, Dennis Thomas and Associates issued a report titled, "Review of the Relationship between Hawaiian Electric Industries and Hawaiian Electric Company" (the "Thomas Report").

Q. What did the Thomas Report conclude regarding the impact of HEI on the Companies' cost of capital?

A. The Thomas Report concluded the following:

1) "Any impacts of diversification on the yield of HECO's debt obligations have likely been transitory and small. Hence, there is no reason to believe that the debt costs reflected in HECO's rates have been changed as a result of HEI's past diversification activities." (Thomas Report, page 132)

2) "Cost of equity witnesses in HECO rate cases have consistently based their estimates on HECO's financial parameters and estimates for the cost of equity to comparable electric utilities . . . the policy of looking directly at

HECO and comparable electric utilities, rather than HEI's cost of equity, has served to insulate HECO's ratepayers from any impact due to changes in HEI's cost of equity." (Thomas report, page 131)

3) "... diversification has not permanently raised or lowered the cost of capital incorporated into the rates that the utility's customers pay." (Thomas Report, page 121)

Q. Did the Commission adopt the Thomas Report?

A. Yes. The Commission adopted the Thomas Report in D&O No. 15225. In its D&O, the Commission also adopted the Department of Defense's recommendation that in rate proceedings the Companies "... present comprehensive analysis of the impact that the holding company structure and investments in non-utility subsidiaries have on its cost of capital to the utility." However, the Commission stated that it "... will apply the recommendation on a <u>case-by-case basis</u> in the Utilities' respective rate cases." (emphasis added) As a result, it is our understanding that the Commission will determine whether a "comprehensive analysis of the impact that the holding company structure and investments in non-utility subsidiaries have" on the cost of capital of HECO should be done in this case.

Q. In previous rate cases, what have the Companies done to address the issue as to whether such a comprehensive analysis should be done?

A. HECO, MECO and HELCO retained Mr. William E. Avera to address the issue in each of their latest test year rate cases [Docket No. 04-0113 (HECO 2005 Test Year), Docket No. 97-0346 (MECO 1999 Test Year), Docket No. 05-0315 (HELCO 2006 Test Year), Docket No. 99-0207 (HELCO 2000 Test Year), and Docket No. 97-0420 (HELCO 1999 Test Year)]. Mr. Avera was the Team Leader for Dennis Thomas and Associates with respect to those sections of the Thomas

Report addressing cost of capital issues (including financial integrity and credit ratings). Mr. Avera's team assembled the material for Chapter 6 – Availability and Cost of Capital to HECO.

Q. What was Mr. Avera's conclusion?

A. Mr. Avera's conclusion is stated in each of his affidavits dated December 28, 1997 (see MECO-1610 in Docket No. 97-0346), March 1, 1998 (see HELCO-1610 in Docket No. 97-0420), October 7, 1999 (see HELCO-1710 in Docket No. 99-0207), November 8, 2004 (see HECO-2118 in Docket No. 04-0113), and May 1, 2006 (see HELCO-1820 in Docket No. 05-0315). In summary, through evaluations that focused primarily on events since the Thomas report was issued in January 1995, Mr. Avera arrived at the following conclusion:

> "In conclusion, my review revealed no evidence that would alter the conclusions reached in the Thomas Report or indicate a fundamental change in investors' perceptions of the relationship between HEI and HECO. The comprehensive analyses conducted in preparing the Thomas Report required almost an entire year to complete and involved an exhaustive review of documents and extensive interviews with members of the investment community in Hawaii, on Wall Street, and in other financial centers. Given that the findings of such a comprehensive review with respect to the availability and cost of capital to HEI and its utility subsidiaries would not be expected to be materially different from those adopted by the PUC in December 1996, it is my opinion that the significant expenditure of time and money involved in conducting such a comprehensive review is not presently warranted."

Q. Did HECO, MECO and HELCO agree with Mr. Avera's conclusions?

A. Yes. A "comprehensive" analysis, such as that done as part of the Thomas Report, was not conducted in connection with the HECO, MECO and HELCO rate cases.

Q. Did the Commission require that a comprehensive analysis be conducted in any of those cases?

A. None was required in the HECO 2005 test year rate case, MECO 1999 test year case, or the HELCO 2000 test year case. The HELCO test year 1999 rate case was withdrawn in 1999.

Q. What has HECO done to address the issue as to whether such a comprehensive analysis should be done in this case?

A. HECO has again retained Mr. Avera.

Q. What is Mr. Avera's current conclusion?

A. Mr. Avera's conclusion is stated in his affidavit, a copy of which is attached as HECO-1916. After conducting an evaluation that focused primarily on events since his last review in 1999, Mr. Avera concluded the same as in his past three affidavits – in part, "my review revealed no evidence that would alter the conclusions reached in the Thomas Report," and "a comprehensive review is not presently warranted."

Q. Does HECO agree with Mr. Avera's current conclusion?

A. Yes. A "comprehensive" analysis, such as that done as part of the Thomas Report, is not warranted in this case.

SAVINGS FROM REVENUE BONDS

Q. H.R.S. Section 39A-208(b) requires that the Commission, in every rate case, make estimates of the savings to HECO's customers resulting from the use of special purpose revenue bonds. Have you prepared such an estimate for the Commission?

A. Yes. The savings estimate, along with an explanation of the savings calculation, is shown in HECO-1917.

CONCLUSION

Q. What is your conclusion regarding the fair rate of return on rate base for test year 2007?

A. The Company believes that the rate of return on rate base found fair and reasonable by the Commission should not be less than its composite cost of capital, and that the Company's composite cost of capital in test year 2007 is expected to be 8.92%. The 8.92% composite cost of capital includes a rate of return on common equity of 11.25%, which is important to the maintenance of the Company's credit quality.

Q. Does this conclude your testimony?

A. Yes, it does.

TAYNE S. Y. SEKIMURA

EDUCATIONAL BACKGROUND AND EXPERIENCE

Present employer:	Hawaiian Electric Company, Inc. 900 Richards Street Honolulu, HI 96813
Current position:	Financial Vice President
Previous positions:	Director, Corporate and Property Accounting Director, Internal Audit Capital Budgets Administrator
Years of service:	15 years
Other experience:	Audit Manager, KPMG Assistant Controller, Long Distance/USA
Certification:	Certified Public Accountant (not in public practice) State of Hawaii
Education:	University of Hawaii at Manoa Bachelor of Business Administration in Accounting
Previous Testimonies:	Maui Electric Company, Ltd Docket No. 94-0345 – Rate Base Hawaii Electric Light Company, Inc. Docket No. 94-0140 – Rate Base Hawaii Electric Light Company, Inc. Docket No. 05-0315 – Cost of Capital Hawaiian Electric Company, Inc. Docket No. 04-0113 – Depreciation Expense and Accumulated Depreciation; Total Average Number of Employees; King Street Office Building Lease; Prepaid Pension Asset; Gains on Sale of Land and Iolani Court Plaza Lease Premium; Accounting for Computer Software Development Costs; Abandoned Capital Project Costs; Maintaining Financial Integrity

Hawaiian Electric Company, Inc.

Composite Embedded Cost of Capital
Test Year 2007 Average
($ Thousands)

		(A)	(B) = (A)/Total(A)	(C)	(D) = (B)*(C)
		Capitalization			
	WP Series Reference	Amount	Percent of Total	Earnings Requirement	Weighted Earnings Requirements
Short-Term Debt	WP-1902	$ 38,971	3.08%	5.00%	0.15%
Long-Term Debt	WP-1903	480,727	38.01%	6.09%	2.31%
Hybrid Securities	WP-1904	27,556	2.18%	7.47%	0.16%
Preferred Stock	WP-1905	20,586	1.63%	5.51%	0.09%
Common Equity	WP-1906	696,825	55.10%	11.25%	6.20%
Total Capitalization		$1,264,666	100.00%		8.92%
Estimated 2007 Test Year Composite Cost of Capital					**8.92%**

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Short-Term Borrowings
Test Year 2007 Average
($ Thousands)

	WP Reference	Total
Short-Term Borrowings as of December 31, 2005	WP-1902, p.1	$ 91,715
2006 Estimated Net Change in Short-Term Borrowings	HECO-1907	(13,773)
Short-Term Borrowings as of December 31, 2006		77,942 (A)
2007 Estimated Net Change in Short-Term Borrowings	HECO-1907	(77,942)
Short-Term Borrowings as of December 31, 2007		$ (0) (B)
Test Year 2007 Average = [(A)+(B)]/2		**$ 38,971**
Earnings Requirement		5.00%
Annual Debt Requirement		**$ 1,949**

Totals may not add exactly due to rounding.

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Hawaiian Electric Company, Inc.

Embedded Cost of Long-Term Debt
Test Year 2007 Average
($ Thousands)

	(A)	(B)	(C) = (A)*(B)	(D) = WP-1903, p.2	(E)	(F) = (C)+(D)+(E)
Long-Term Debt	Rate	Net Proceeds	Annual Interest	Annual Amortization	Annual Insurance Premium	Annual Requirement
Special Purpose Revenue Bonds (Refunded Issue):						
Series 1993	5.45%	$ 50,000	$ 2,725	$ 89		$ 2,814
Series 1996A	6.20%	48,000	2,976	79		3,055
Series 1996B	5 7/8%	14,000	823	8	13 [A]	844
Series 1997A	5.65%	50,000	2,825	61	45 [B]	2,931
Refunding Series 1998A (1987)	4.95%	42,580	2,108	254		2,362
Refunding Series 1999B (1988)	5.75%	30,000	1,725	118		1,843
Series 1999C	6.20%	35,000	2,170	63		2,233
Refunding Series 1999D (1990A)	6.15%	16,000	984	49		1,033
Refunding Series 2000 (1990B&C)	5.70%	46,000	2,622	181		2,803
Series 2002A	5.10%	40,000	2,040	120		2,160
Refunding Series 2003B (1992)	5.00%	40,000	2,000	195		2,195
Refunding Series 2005A (1995A)	4.80%	40,000	1,920	158		2,078
Series 2007 (new issue)	5.50%	50,000 [C]	2,750	66		2,816
		501,580	27,667	1,441	58	29,166
Unamortized Costs, Revenue Bonds *		(20,096)				
Unamortized Costs, First Mtg Bonds **		(627)		67		67
Unamortized Costs, SCF ***		(129)		34		34
Test Year 2007 Average		**$ 480,727**	**$ 27,667**	**$ 1,542**	**$ 58**	**$ 29,267**
Effective Rate = Total(F)/Total(B)						**6.09%**

* Issuance costs, redemption costs, issuance discounts, and investment income differentials are included in this amount. Refer to WP-1903, p.1 for detail.

** Unamortized costs relate to HECO's First Mortgage Bonds which were redeemed prior to December 31, 2005. Refer to WP-1903, p.8 for First Mortgage Bonds unamortized costs.

*** Unamortized costs relate to HECO's share of the issuance costs for the Multi-year Syndicated Credit Facility (SCF) pending PUC approval in Docket No. 2006-0360 (filed August 30, 2006). Refer to WP-1903, p. 9 for SCF issuance costs.

A. Based on 9 basis points annually of outstanding par beginning in 2006.
B. Based on 9 basis points annually of outstanding par beginning in 2007.
C. Based on average balance at 12/31/06 of $0 and 12/31/07 of $100,000.

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Embedded Cost of Hybrid Securities
Test Year 2007 Average
($ Thousands)

	(A)	(B)	(C) = (A)*(B)	(D) = (A)*(B)	(E)	(F) = (C)+(D)+(E)
Hybrid Security	Rate/ Return	2007 Test Year Average	Interest Expense	Equity in Net Income of Trust	Annual Amortization	Annual Requirement
Series 2004	6.50%	$ 31,546	$ 2,051			$ 2,051
Investment in HECO Capital Trust III	6.50% *	(1,546)		$ (101)		(101)
Unamortized Issuance Costs **		(2,444)			$ 109	109
Test Year 2007 Average		**$ 27,556**	**$ 2,051**	**$ (101)**	**$ 109**	**$ 2,059**
Effective Rate = Total(F)/Total(B)						**7.47%**

* Estimated based on the 6.5% Cumulative Quarterly Income Preferred Securities, Series 2004 issued by HECO Capital Trust III. Refer to WP-1904, p.1 for calculation of average 2007 balance.

** Includes unamortized issuance costs of current and previously redeemed hybrid securities. Refer to HECO-WP-1904, p.2.

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Embedded Cost of Preferred Stock
Test Year 2007 Average
($ Thousands)

	(A)	(B)	(C) = (A)*(B)	(D)	(E) = (C)+(D)
Preferred Stock	Rate	2007 Test Year Average	Annual Dividends	Annual Amortization	Annual Requirement
Perpetual Series *:					
Series C	4 1/4%	$ 3,000	$ 128	$ -	$ 128
Series D	5%	1,000	50	-	50
Series E	5%	3,000	150	-	150
Series H	5 1/4%	5,000	263	-	263
Series I	5%	1,793	90	-	90
Series J	4 3/4%	5,000	238	-	238
Series K	4.65%	3,500	163	-	163
		22,293	1,080	0	1,080
Unamortized Costs **		(1,707)		55	55
Test Year 2007 Average		**$ 20,586**	**$ 1,080**	**$ 55**	**$ 1,135**
Effective Rate = Total(E)/Total(C)					**5.51%**

* Represents preferred stock not subject to mandatory redemption. Therefore, issuance costs are not amortized.

** Refer to WP-1905, p.1 for detail.

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Common Equity
2007 Average
($ Thousands)

	WP Reference		RATEMAKING Total	BOOK Total
Book Common Equity as of December 31, 2005	WP-1906, p.1		$ 655,544	$ 655,544
Restoration	WP-1906 p.2		523	-
Reversal of AOCI adj related to nonqualified plans			28	-
Common Equity Investment as of December 31, 2005			656,095	655,544
2006 Estimated Net Change in Retained Earnings	HECO-1907		27,998	27,998
2006 Est Net AOCI adj related to Exec Life, net of tax			944	944
Reversal of 2006 AOCI adj for Ratemaking			(944)	-
Common Equity as of December 31, 2006		(A)	684,093	684,486
2007 Estimated Net Change in Retained Earnings	HECO-1907		25,465	25,465
2007 Est Net AOCI adj related to Exec Life, net of tax			487	487
Reversal of 2007 AOCI adj for Ratemaking			(487)	-
Common Equity as of December 31, 2007		(B)	$ 709,558	$ 710,438
Test Year 2007 Average = [(A)+(B)]/2			**$ 696,825**	
Book 2007 Average = [(A)+(B)]/2				$ 697,462

Totals may not add exactly due to rounding.

Filename: Cost of Cap_1901 to 1907 .xls 1906 Equity

Hawaiian Electric Company, Inc.

Sources and Applications of Funds
($ Thousands)

	Recorded 2005	Forecast 2006	Forecast 2007
Application of Funds:			
Capital Expenditures	$ 138,058	$ 102,357	$ 95,661
Less: CIAC & Advances	19,315	25,153	8,846
Less: AFUDC	5,606	5,265	4,994
Net Capital Expenditures	$ 113,137	$ 71,939	$ 81,821
Debt Redemption	$ -	$ -	$ -
Hybrid Redemption	-	-	-
Total Applications	$ 113,137	$ 71,939	$ 81,821
Sources of Funds:			
Internal Sources:			
Retained Earnings	$ 14,404	$ 27,998	$ 25,465
Depreciation & Amortization	76,703	75,714	79,370
Deferred Taxes & ITC	15,103	(7,789)	587
Other (Misc. Net Changes in Working Capital)	(36,403)	(10,211)	(18,024)
Total Internal Sources	$ 69,807	$ 85,712	$ 87,398
External Sources:			
Increase (Decrease) in Short-Term Borrowings	$ 30,247	$ (13,773)	$ (77,942)
Drawdown of Revenue Bond Proceeds	13,083	-	100,000
Temporary Investments	-	-	(27,635)
Total External Financing	$ 43,330	$ (13,773)	$ (5,577)
Total Sources	$ 113,137	$ 71,939	$ 81,821

Totals may not add exactly due to rounding.

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

Key Credit Factors:

Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers

Publication date: 14-Sep-2006
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The methodology that Standard & Poor's Ratings Services uses to rate vertically integrated electric, gas, and combination investor-owned utilities in the U.S. is based on the same precepts that we have used for many years, though the emphasis has changed as the utility industry has evolved. The fundamental methodology encompasses two basic components--business risk and financial risk--and their relationship. Where a utility presents a strong business risk profile, the financial profile can be less robust for any given rating. Likewise, where a utility's business risk profile is weaker, its financial performance must be stronger for any given rating. For combination utilities, the gas operations may have a stabilizing influence on credit quality, but since the electric business is typically significantly larger, it is the major credit driver. (For details on Standard & Poor's analytical approach to gas utilities, see "Key Credit Factors For Natural Gas Distributors" published Feb. 28, 2006.)

Often, an integrated utility is a part of a larger holding company structure that also owns other businesses, frequently unregulated electricity generation. This fact does not alter how we analyze the utility, but it may affect the ultimate rating outcome due to any credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

Five Factors Determine The Business Profile

Five basic characteristics define a vertically integrated utility's business profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Standard & Poor's is most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations. While considerable attention has focused in recent years on companies in states that deregulated in the late 1990s and the early part of this decade and the related credit consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management loom considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

On Standard & Poor's business profile scale (where '1' is excellent and '10' is vulnerable), vertically integrated utilities generally have satisfactory business profiles of '5' or '6'. (See tables 1 and 2 in the Appendix below for business profile benchmarks plus a list of utilities we rate and their business profile scores.) We view a company that owns regulated generation, transmission, and distribution operations, as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management.

Regulation

Regulation is a critical aspect that underlies integrated utilities' creditworthiness. Decisions by state public service commissions can profoundly affect financial performance. Standard & Poor's assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program and incurs substantial deferrals of fuel costs.

Standard & Poor's evaluation encompasses the administrative, judicial, and legislative processes involved in state and federal regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case-by-case with regard to the potential effect on credit quality. As frequently postulated in prior years, our evaluation of regulation focuses on the willingness and ability of regulation to provide cash flow and earnings quality adequate to meet investment needs, earnings stability through timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity. Regulators' authorization of high rates of return is of little value unless returns are realistic and achievable. Allowing high returns based on noncash items does not benefit bondholders. A regulatory jurisdiction that permits incentives whereby utilities are allowed to earn a return based on their ability to sustain rates at competitive levels is viewed favorably. In addition to performance-based rewards or penalties, flexible plans could include market-based rates, price caps, index-based prices, and rates premised on the value of customer service. Also important is the ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses or with fixed-fuel mechanisms, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. Standard & Poor's notes that fuel-adjustment mechanisms have become more common in the industry, but not all are created equal. While some jurisdictions permit recovery on a dollar-for-dollar basis over a defined time period, certain jurisdictions, such as Washington State, impose a deadband in which the company absorbs all the risk and rewards of fuel costs above and below the established recovery rate. Beyond the deadband there is a sharing of risks and rewards with ratepayers. In Arizona, Arizona Public Service Co. has a 90/10 sharing mechanism between the company and ratepayers, respectively, for all costs passed through the power supply adjuster. The mechanism is triggered based on a date (once a year in February 2006) and not on a threshold level of deferrals. The annual adjustment is also subject to a lifetime cap of 4 mils per kilowatt-hour, which has led to power deferrals.

In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise be a sometimes significant cash flow drain and reduces the utility's need to issue debt during construction.

Moreover, allowing rate recovery of projected costs with subsequent periodic updates for actual results reduces lags in cost recovery. Also supportive of credit quality is the ability of the utility, commission staff, consumer advocates, and other major interveners to reach a comprehensive settlement before construction of new base load capacity. Certain states, such as Indiana, Texas, Kansas, and Minnesota, have adopted environmental tracking mechanisms and other riders that allow companies to reflect in rates capital costs associated with environmental compliance equipment without having to file a formal rate case. Creditworthiness can also be enhanced when a company has the authority to timely recover unanticipated costs, such as those incurred for repairing storm damage, as in Florida. While the Alabama Public Service Commission does not currently employ a separate storm repair cost recovery mechanism to ensure rapid recovery of storm repair costs, it has shown a willingness to work with utilities to help them recover at least some of these costs on a timely basis and to start replenishing storm reserves. Finally, the greater the percentage of a utility's rates that are recovered through fixed charges rather than volume-based charges, the greater the support for credit quality.

For utilities that own a natural gas business, automatic and timely pass-through of commodity costs provides the strongest level of credit support. Lesser clauses, including mechanisms that require after-the-fact sign-off by regulators, introduce the potential for disallowance if the regulator deems gas to be purchased at imprudent cost levels.

Due to the extreme volatility and high gas prices over the past few heating seasons, more regulators have revised gas adjustment clauses to provide monthly gas adjustments rather than awaiting the end of the heating season to begin reimbursement. This expedited treatment helps the utility to reduce any regulatory lag to recover costs and streamlines working capital needs, which in turn should allow the firm to modestly temper rising gas bills to their customers.

Both regulators and natural gas companies are increasing customer-education programs on energy efficiency and conservation. Lawmakers, state regulators, and companies are in preliminary discussions to potentially restructure the current rate structures to encourage these goals of energy conservation and efficiency without hurting the company's bottom line and still allow utilities to achieve their approved regulated rate of return. In essence, "conservation tariffs" would aim to decouple earnings and rates of return from delivered volumes and should eliminate a current major disincentive for utilities to develop such conservation programs. This would also better align the interest of consumers with utility shareholders by implementing innovative rate designs that would encourage energy conservation and efficiency.

Key success factors include:

- Alternative ratemaking/flexibility,
- Attention to credit quality,
- Timely and consistent rate treatment,
- Support for fuel cost recovery,
- Support for a reasonable cash return on investment, and
- Support for rapid return on investment.

Markets

Assessing market dynamics begins with an economic and demographic evaluation of the service area in which a utility operates. Strength of long-term demand for energy is examined from a macroeconomic perspective, which enables Standard & Poor's to measure the affordability of rates and the staying power of demand. Distribution by classification according to total number of customers, revenues, and margins is closely scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed with some caution because the utility may be exposed to cyclical volatility and face competitive alternatives. A large residential component, on the other hand, produces a more stable and predictable revenue stream. The utility's largest customers are identified to determine their stability and importance to the bottom line because the loss of one large customer could adversely affect the utility's financial position. Moreover, large customers may turn to self-generation, potentially leading to less financial protection for the utility.

Standard & Poor's also analyzes any long-term consumption trends and the reasons behind them. Factors addressed include the market's size and growth rate, the franchise's strength, historical and projected growth rates, income levels and trends in population, employment, and per capita income. A utility with a healthy economy and customer base, as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment, will be better able to support its operations.

For the gas business, Standard & Poor's also examines customer saturation. Firms that operate in service areas with low growth potential still can expand at healthy rates if a relatively low level of customer saturation permeates the service territory. For example, customers who convert to natural gas from other fuel sources (such as oil) provide growth opportunities to companies operating in low population growth service areas.

Despite the review of market characteristics, they are clearly a secondary consideration to regulation. In Nevada, for years the country's fastest growing state, Nevada Power Co. and Sierra Pacific Power Co. struggled to recover capital expenditures on a timely basis, and were accordingly rated as low investment-grade credits. In Florida, which has competed with Nevada for years in its pace of growth, the Florida Public Service Commission established polices of quick recovery of capital investments and, on a stand-alone basis, the state's utilities' credit metrics have remained strong.

Critical success factors include:

- A healthy and growing economy,
- Growth in population and number of customers,
- An attractive business environment, and
- An above-average residential base.

Operations

Standard & Poor's focuses on cost, reliability, safety, and quality of service when assessing a utility's operations. Management is always under pressure to optimize the use of resources, and if it is not cost-effective in meeting service standards and reliability, regulatory or competitive pressures are likely to increase. Consequently, Standard & Poor's emphasizes areas that require heightened and ongoing management attention, in the absence of which political, regulatory, or competitive problems are likely to arise.

The status of utility plant investment is reviewed with regard to generating station availability, efficiency, and utilization, as well as for compliance with existing and potential environmental and other regulatory standards. The record of plant outages, system losses, equivalent availability, load factors, heat rates, and capacity factors are examined. Important considerations include the projected capital improvements and plant additions necessary to provide high-quality, reliable service. The general condition of the assets and how well such assets are maintained are also important considerations.

Emphasis is placed on reserve margins, fuel mix, fuel contract terms, purchased-power arrangements, and system operators. Moreover, the quality and concentration of capacity is just as important as the size of reserves. Standard & Poor's recognizes that reserve requirements differ among companies, depending upon individual operating and load characteristics.

Fuel diversity provides flexibility in a changing environment. Supply disruptions and price hikes can raise rates and ignite political and regulatory pressures that ultimately lead to erosion in financial performance. Thus, the ability to switch generating sources to take advantage of cheaper fuels is viewed favorably. Dependence on any single fuel, or asset concentration in one or two large generating stations, can cause significant swings in a company's financial performance. Similarly, utilities that rely on nuclear generation receive an elevated degree of attention due to the scale, technical complexity, and politically sensitive nature of nuclear facilities. Indeed, the sound operation of nuclear units can define a utility's operational risk profile and its ability to achieve projected financial results. Standard & Poor's seeks to distinguish between those operators that have exhibited sound and stable operational performance, and the likelihood that it will continue, and those whose nuclear operations are vulnerable to problems that may impair financial results.

But having a large concentration of capacity based on fossil fuels also imposes certain risks. Coal-fired capacity is burdened with increased environmental costs related to reducing sulfur dioxide, nitrogen oxide, mercury, and eventually carbon dioxide emissions. Gas-fired capacity presents its own challenges, particularly the extreme volatility and significant increase in gas prices over the past few years. Buying power may be a more appropriate option for a utility than new plant construction because the utility avoids construction costs and the financial risks posed by regulatory lag when seeking recovery of costs. Purchasing power may enhance supply flexibility, fuel resource diversity, and maximize load factors. Utilities that plan to meet demand projections with a portfolio of supply-side options also may be better able to adapt to future growth uncertainties. Despite these benefits, such a strategy does commit the utility to a fixed obligation, which Standard & Poor's captures analytically through certain adjustments to financial statements. We calculate the net present value of future annual capacity payments (discounted at the company's cost of debt) over the life of the contract. Standard & Poor's then applies a risk factor against this value and adds the result to the utility's balance sheet. The risk factor is largely a function of the strength of the regulatory recovery mechanisms established to address procurement costs.

Other operational characteristics that will support an above-average evaluation for vertically integrated companies are assets that are in good physical condition and are well maintained. In addition, capital expenditures for necessary system improvements must be at manageable levels, yet sufficient to provide for constant renewal and refurbishment of the system. Operating performance, reliability statistics (such as outage duration and frequency), and efficiency measures are expected to meet industry and regional averages. Having interconnections that provide access to low-cost and diverse power supply sources is viewed favorably, as is limited environmental exposure.

For a gas company, drawing from a single interstate pipeline or relying on a particular gas basin exposes it to event risk and negative supply shocks, respectively. The ability to access multiple sources of gas supply through multiple pipelines protects the utility from such disruptions. Adequate storage access not only helps supply incremental gas needed to meet peak demand, but also provides opportunities without purchased-gas adjustment clauses to arbitrage seasonal pricing fluctuations. Gas distributors benefit from storage if the cost of buying peak gas exceeds the cost of making off-season purchases and the associated carrying cost. Outdated systems requiring extensive maintenance and capital expenditures lower profitability and efficiency metrics. Newly installed systems mainly consisting of plastic pipe require limited expenditures over the long term compared with older, cast-iron systems that need replacing as they age. In addition, operational efficiencies can be obtained through the use of new technology.

Critical success factors include:

- Well-maintained assets,
- Solid plant performance,
- Fuel diversity,
- Adequate generating reserves, and
- Compliance with environmental standards.

Competitiveness

For vertically integrated utilities, competitive factors include percentage of firm wholesale revenues that are most vulnerable to competition, industrial load, and revenue concentrations, particularly in energy intensive industries; exposure of key customers to alternative suppliers; commercial concentrations; rates charged to various customer classes; rate design and flexibility; production costs, both marginal and fixed; the regional capacity situation; and transmission constraints. A regional focus is evident, but high costs and rates relative to national averages are also of significant concern because of the potential for electricity substitutes over time.

Electricity competes with other fuels--particularly natural gas--for certain segments of the market like space heating, water heating, and cooking. Thus, high electricity prices, which can be attributed to inefficient operations, are cause for concern if customers have access to alternative energy sources. Self-generation has been a risk, as large commercial and industrial customers may take advantage of cogeneration technologies to reduce their reliance on, and in some cases to disconnect from the system. In the future, technology could pose a greater threat. Bypass risk, too, may grow if distributed generation, microgeneration, and self-generation prove more economically attractive for smaller customers.

Due to their proximity to interstate gas pipelines, some large customers can directly tie into a transmission line and completely bypass gas distributors' services. Although such pipelines provide key sources of gas supply for these companies, it is important to recognize this bypass risk. Ideally located gas companies have adequate transmission access but have industrial customers far from interstate pipelines.

Critical success factors include:

- Low cost structure,
- Limited bypass risk, and
- Management's commitment to lowering costs.

Management

Evaluating management is of paramount importance to Standard & Poor's analysis because management decisions affect all areas of a company's operations and financial health. Although regulation, the economy, and other outside factors certainly influence results, the quality of management ultimately determines a company's success. Standard & Poor's private meetings with senior management significantly augment the public record in the effort to appraise management. Meetings are very useful for the candid interpretation of recent developments and, importantly, to provide executives with a forum for the presentation of goals, objectives, and strategies.

Management assessment is based on tenure, turnover, industry experience, financial track record, corporate governance, a grasp of industry issues, and knowledge of regulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple--and often incompatible--priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

Standard & Poor's also focuses on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

In addition, a company's accounting and financing practices are critical to Standard & Poor's analysis. For example, proactive management will likely adopt accounting practices that are more appropriate in a competitive environment such as higher depreciation rates for electric generation equipment. Large, growing cost deferrals or regulatory assets are viewed more negatively. Management can enhance its financial condition by taking any number of discretionary actions, such as selling common equity, reducing the common dividend payout, and deleveraging. A utility's management will also be evaluated on cost-cutting ability and creativity in entering into strategic alliances that improve efficiency.

Strong corporate governance, reflected in active, independent board of directors that participate in determining and monitoring corporate controls, help to support management's credibility and corporate financial disclosure. If it is evident that a company's board is passive and does not exercise proper oversight, it weakens the checks and balances of the organization and may detract from credit quality. Included in Standard & Poor's review of corporate governance is the proportion of independent directors on the board, the breadth and depth of the directors' experience, the proportion of independent directors on the board's audit committee, and directors' compensation.

Some vertically integrated utilities have felt compelled to invest outside their traditional businesses to increase earnings, especially as stock prices have underperformed market indices. Participation in higher-risk, unregulated activities such as merchant generation, exploration and development, gathering and processing, or marketing and trading can significantly detract from the consolidated entity's credit profile. In this regard, credit ratings are not based on the regulated business only, but on the qualitative and quantitative fundamentals of the consolidated entity. Standard & Poor's considers the ratings of the regulated businesses as being less vulnerable to the negative credit influence of other affiliates and holding company activities, as relevant, where very strong structural and/or regulatory insulation exists, which tends to be more the exception than the rule.

Critical success factors include:

- Commitment to credit quality,
- Credibility,
- Strong corporate governance, and
- Conservative financial policies, especially regarding nonregulated activities, if relevant.

Effect On Ratings

In summary, Standard & Poor's examines the key business risk drivers for vertically integrated utilities--regulation, markets, operations, competitiveness, and management--in conjunction with financial measures when assigning credit ratings. The credit quality of most vertically integrated utilities is solidly investment grade. This is a primarily a function of the existence of regulation. As discussed above, the factors that further differentiate ratings among this sector include their markets, operational track record, competitive posture, and management's risk appetite. Vertically integrated utilities generally have satisfactory business risk profile scores, with only a few having strong or weak business positions.

Appendix

Table 1

Industry Benchmarks

Business Profile	AA		A		BBB		BB	
Adjusted FFO interest coverage (x)								
1	3.0	2.5	2.5	1.5	1.5	1.0	< 1.0	< 1.0
2	4.0	3.0	3.0	2.0	2.0	1.0	< 1.0	< 1.0
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1.0
4	5.0	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6.0	5.2	5.2	4.2	4.2	3.0	3.0	2.0
7	8.0	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10.0	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9	N/A	N/A	10.0	7.0	7.0	4.0	4.0	2.8
10	N/A	N/A	11.0	8.0	8.0	5.0	5.0	3.0
Adjusted FFO/average total debt (%)								
1	20.0	15.0	15.0	10.0	10.0	5.0	< 5.0	< 5.0
2	25.0	20.0	20.0	12.0	12.0	8.0	< 8.0	< 8.0
3	30.0	25.0	25.0	15.0	15.0	10.0	10.0	5.0
4	35.0	28.0	28.0	20.0	20.0	12.0	12.0	8.0
5	40.0	30.0	30.0	22.0	22.0	15.0	15.0	10.0
6	45.0	35.0	35.0	28.0	28.0	18.0	18.0	12.0
7	55.0	45.0	45.0	30.0	30.0	20.0	20.0	15.0
8	70.0	55.0	55.0	40.0	40.0	25.0	25.0	15.0
9	N/A	N/A	65.0	45.0	45.0	30.0	30.0	20.0
10	N/A	N/A	70.0	55.0	55.0	40.0	40.0	25.0
Adjusted total debt/total capital (%)								
1	48.0	55.0	55.0	60.0	60.0	70.0	> 70.0	> 70.0
2	45.0	52.0	52.0	58.0	58.0	68.0	> 68.0	> 68.0
3	42.0	50.0	50.0	55.0	55.0	65.0	65.0	70.0
4	38.0	45.0	45.0	52.0	52.0	62.0	62.0	68.0
5	35.0	42.0	42.0	50.0	50.0	60.0	60.0	65.0
6	32.0	40.0	40.0	48.0	48.0	58.0	58.0	62.0
7	30.0	38.0	38.0	45.0	45.0	55.0	55.0	60.0
8	25.0	35.0	35.0	42.0	42.0	52.0	52.0	58.0
9	N/A	N/A	32.0	40.0	40.0	50.0	50.0	55.0

10	N/A	N/A	25.0	35.0	35.0	48.0	48.0	52.0

Note: Business profile scores are characterized from '1' (excellent) to '10' (weak). FFO--Funds from operations. N/A--Not applicable.

Table 2

Vertically Integrated Utilities

Company	Corporate credit rating	Business profile score
Aquila Inc.	B/CW-Pos/B-2	6
AGL Resources Inc.	A-/Negative/A-2	4
Alabama Power Co.	A/Stable/A-1	4
ALLETE Inc.	BBB+/Stable/A-2	5
Ameren Corp.	BBB+/CW-Neg/A-2	6
Appalachian Power Co.	BBB/Stable/--	5
Arizona Public Service Co.	BBB-/Stable/A-3	6
Atmos Energy Corp.	BBB/Stable/A-2	4
Black Hills Power Inc.	BBB-/Negative/--	6
Central Illinois Light Co.	BBB+/CW-Neg/--	7
Central Vermont Public Service Corp.	BB+/Stable/--	6
CILCORP Inc.	BBB+/CW-Neg/--	7
Cincinnati Gas & Electric Co.	BBB/Positive/A-2	6
Cleco Power LLC	BBB/Negative/--	6
Cleveland Electric Illuminating Co.	BBB/Stable/--	6
Consolidated Natural Gas Co.	BBB/Stable/A-2	6
Consumers Energy Co.	BB/Stable/--	6
Dayton Power & Light Co.	BB+/Positive/--	5
Detroit Edison Co.	BBB/Stable/A-2	6
Duke Power Co. LLC	BBB/Positive/A-2	4
El Paso Electric Co.	BBB/Stable/--	6
Empire District Electric Co.	BBB-/Stable/A-3	6
Energy East Corp.	BBB+/Negative/A-2	3
Enogex Inc.	BBB+/Stable/--	7
Entergy Arkansas Inc.	BBB/Negative/--	5
Entergy Gulf States Inc.	BBB/Negative/--	6
Entergy Louisiana LLC	BBB/Negative/--	5
Entergy Mississippi Inc.	BBB/Negative/--	6
Entergy New Orleans Inc.	D/--/--	8
Equitable Resources Inc.	A-/CW-Neg/A-2	8
Florida Power & Light Co.	A/CW-Neg/A-1	4
Georgia Power Co.	A/Stable/A-1	4
Green Mountain Power Corp.	BBB/CW-Pos/--	5
Gulf Power Co.	A/Stable/--	4
Hawaiian Electric Co. Inc.	BBB+/Negative/A-2	5
IDACORP Inc.	BBB+/Negative/A-2	5
Idaho Power Co.	BBB+/Negative/A-2	5
Indiana Michigan Power Co.	BBB/Stable/--	6
Indianapolis Power & Light Co.	BB+/Positive/--	4
Interstate Power & Light Co.	BBB+/Stable/A-2	5
IPALCO Enterprises Inc.	BB+/Positive/--	4
Kansas City Power & Light Co.	BBB/Stable/A-2	6
Kansas Gas & Electric Co.	BB+/Positive/--	6
Kentucky Power Co.	BBB/Stable/--	5
Kentucky Utilities Co.	BBB+/Stable/A-2	5
Louisville Gas & Electric Co.	BBB+/Stable/--	5

Madison Gas & Electric Co.	AA-/Stable/A-1+	4
Michigan Consolidated Gas Co.	BBB/Stable/A-2	4
MidAmerican Energy Co.	A-/Stable/A-1	5
Mississippi Power Co.	A/Stable/A-1	4
Monongahela Power Co.	BB+/Positive/--	5
Montana-Dakota Utilities Co.	BBB+/Stable/--	6
National Fuel Gas Co.	BBB+/Stable/A-2	7
Nevada Power Co.	B+/Positive/--	6
New York State Electric & Gas Corp.	BBB+/Negative/A-2	3
NiSource	BBB/Stable/--	4
Northern Indiana Public Service Co.	BBB/Stable/--	5
Northern States Power Co.	BBB/Stable/A-2	5
Northern States Power Wisconsin	BBB+/Stable/--	4
Ohio Edison Co.	BBB/Stable/A-2	6
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	5
Pacific Gas & Electric Co.	BBB/Stable/A-2	5
PacifiCorp	A-/Stable/A-1	5
Pennsylvania Power Co.	BBB/Stable/--	6
Pinnacle West Capital Corp.	BBB-/Stable/A-3	6
PNM Resources Inc.	BBB/Negative/A-3	6
Portland General Electric Co.	BBB+/Negative/A-2	5
Progress Energy Carolinas Inc.	BBB/PositiveA-2	5
Progress Energy Florida Inc.	BBB/Positive/A-2	4
PSI Energy Inc.	BBB/Positive/A-2	4
Public Service Co. of Colorado	BBB/Stable/A-2	4
Public Service Co. of New Hampshire	BBB/Stable/--	5
Public Service Co. of New Mexico	BBB/Negative/A-3	6
Public Service Co. of Oklahoma	BBB/Stable/--	5
Puget Energy Inc.	BBB-/Stable/--	4
Puget Sound Energy Inc.	BBB-/Stable/A-3	4
Questar Market Resources Inc.	BBB+/Stable/---	8
Rochester Gas & Electric Corp.	BBB+/Negative/--	3
San Diego Gas & Electric Co.	A/Stable/A-1	5
Savannah Electric & Power Co.	A/Stable/--	4
SCANA Corp.	A-/Stable/--	4
Sierra Pacific Power Co.	B+/Positive/--	6
Sierra Pacific Resources	B+/Positive/B-2	6
South Carolina Electric & Gas Co.	A-/Stable/A-2	4
Southern California Edison Co.	BBB+/Stable/A-2	6
Southern Co.	A/Stable/A-1	4
Southern Indiana Gas & Electric Co.	A-/Stable/--	4
Southwestern Electric Power Co.	BBB/Stable/--	5
Southwestern Public Service Co.	BBB/Stable/A-2	5
System Energy Resources Inc.	BBB-/Negative/--	7
Tampa Electric Co.	BBB-/Stable/A-3	4
Toledo Edison Co.	BBB/Stable/--	6
Tucson Electric Power Co.	BB/Stable/B-2	6
TXU U.S. Holdings Co.	BBB-/Negative/--	8
Union Electric Co.	BBB+/CW-Neg/A-2	5
Union Light Heat & Power Co.	BBB/Positive/--	5
Vectren Utility Holdings Inc.	A-/Stable/A-2	3
Virginia Electric & Power Co.	BBB/Stable/A-2	5

Westar Energy Inc.	BB+/Positive/--	5
Wisconsin Electric Power Co.	A-/Negative/A-2	4
Wisconsin Energy Corp.	BBB+/Negative/A-2	5
Wisconsin Power & Light Co.	A-/Stable/A-2	4
Wisconsin Public Service Corp.	A+/CW-Neg/A-1	4
Xcel Energy Inc.	BBB/Stable/A-2	5

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Forward-Looking Statements

This report and other presentations made by Hawaiian Electric Industries, Inc. (HEI) and Hawaiian Electric Company, Inc. (HECO) and their subsidiaries contain "forward-looking statements," which include statements that are predictive in nature, depend upon or refer to future events or conditions, and usually include words such as "expects," "anticipates," "intends," "plans," "believes," "predicts," "estimates" or similar expressions. In addition, any statements concerning future financial performance, ongoing business strategies or prospects and possible future actions are also forward-looking statements. Forward-looking statements are based on current expectations and projections about future events and are subject to risks, uncertainties and the accuracy of assumptions concerning HEI and its subsidiaries (collectively, the Company), the performance of the industries in which they do business and economic and market factors, among other things. **These forward-looking statements are not guarantees of future performance.**

Risks, uncertainties and other important factors that could cause actual results to differ materially from those in forward-looking statements and from historical results include, but are not limited to, the following:

- the effects of international, national and local economic conditions, including the state of the Hawaii tourist and construction industries, the strength or weakness of the Hawaii and continental U.S. real estate markets (including the fair value of collateral underlying loans and mortgage-related securities) and decisions concerning the extent of the presence of the federal government and military in Hawaii;
- the effects of weather and natural disasters, such as hurricanes, earthquakes and tsunamis;
- global developments, including the effects of terrorist acts, the war on terrorism, continuing U.S. presence in Iraq and Afghanistan, potential conflict or crisis with North Korea and in the Middle East, North Korea's and Iran's nuclear activities and potential avian flu pandemic;
- the timing and extent of changes in interest rates and the shape of the yield curve;
- the risks inherent in changes in the value of and market for securities available for sale and pension and other retirement plan assets;
- changes in assumptions used to calculate retirement benefits costs and changes in funding requirements;
- increasing competition in the electric utility and banking industries (e.g., increased self-generation of electricity may have an adverse impact on HECO's revenues and increased price competition for deposits, or an outflow of deposits to alternative investments, may have an adverse impact on American Savings Bank, F.S.B.'s (ASB's) cost of funds);
- capacity and supply constraints or difficulties, especially if generating units (utility-owned or independent power producer (IPP)-owned) fail or measures such as demand-side management (DSM), distributed generation (DG), combined heat and power (CHP) or other firm capacity supply-side resources fall short of achieving their forecasted benefits or are otherwise insufficient to reduce or meet peak demand;
- increased risk to generation reliability as generation reserve margins on Oahu continued to be strained;
- fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses;
- the ability of IPPs to deliver the firm capacity anticipated in their power purchase agreements (PPAs);
- the ability of the electric utilities to negotiate, periodically, favorable fuel supply and collective bargaining agreements;
- new technological developments that could affect the operations and prospects of HEI and its subsidiaries (including HECO and its subsidiaries and ASB and its subsidiaries) or their competitors;
- federal, state and international governmental and regulatory actions, such as changes in laws, rules and regulations applicable to HEI, HECO and their subsidiaries (including changes in taxation, environmental laws and regulations and governmental fees and assessments); decisions by the Public Utilities Commission of the State of Hawaii (PUC) in rate cases and other proceedings and by other agencies and courts on land use, environmental and other permitting issues; required corrective actions, restrictions and penalties (that may arise with respect to environmental conditions, renewable portfolio standards (RPS), capital adequacy and business practices);
- increasing operations and maintenance expenses for the electric utilities and the possibility of more frequent rate cases;
- the risks associated with the geographic concentration of HEI's businesses;
- the effects of changes in accounting principles applicable to HEI, HECO and their subsidiaries, including the adoption of new accounting principles (such as the effects of Statement of Financial Accounting Standards (SFAS) No. 158 regarding employers' accounting for defined benefit pension and other postretirement plans), continued regulatory accounting under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and the possible effects of applying Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46R, "Consolidation of Variable Interest Entities," and Emerging Issues Task Force Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease," to power purchase arrangements with independent power producers;
- the effects of changes by securities rating agencies in their ratings of the securities of HEI and HECO and the results of financing efforts;
- faster than expected loan prepayments that can cause an acceleration of the amortization of premiums on loans and investments and the impairment of mortgage servicing rights of ASB;
- changes in ASB's loan portfolio credit profile and asset quality which may increase or decrease the required level of allowance for loan losses;
- changes in ASB's deposit cost or mix which may have an adverse impact on ASB's cost of funds;
- the final outcome of tax positions taken by HEI, HECO and their subsidiaries;
- the ability of consolidated HEI to generate capital gains and utilize capital loss carryforwards on future tax returns;
- the risks of suffering losses and incurring liabilities that are uninsured; and
- other risks or uncertainties described elsewhere in this report and in other periodic reports (e.g., "Item 1A. Risk Factors" in the Company's Annual Report on Form 10-K) previously and subsequently filed by HEI and/or HECO with the Securities and Exchange Commission (SEC).

Forward-looking statements speak only as of the date of the report, presentation or filing in which they are made. Except to the extent required by the federal securities laws, HEI and its subsidiaries undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

Summary:

Hawaiian Electric Company, Inc.

Publication date: 22-Nov-2006
Primary Credit Analyst: Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com

Credit Rating: BBB+/Negative/A-2

Rationale

The ratings on Hawaiian Electric Co. Inc. are based on the consolidated credit profile of Hawaiian Electric Industries, Inc. (HEI), which includes Hawaiian Electric's utility operations and its two subsidiaries Hawaiian Electric Light Co. (HELCO) and Maui Electric Co. (82% of core revenues and 61% of operating income as of Dec. 31, 2005), and the riskier financial services operations of American Savings Bank FSB, (18% of core revenues and 39% of operating income). Standard & Poor's Ratings Services does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI.

HEI's consolidated financial condition remains somewhat weak for the rating despite the strong Hawaiian economy and the company's efforts in recent years to strengthen its capital structure. On a stand-alone basis, Hawaiian Electric has a healthier financial profile owing to a lower debt burden. Financial metrics have been pressured owing to rising operating and maintenance expenses, increasing capital outlays, the prolonged lack of rate relief, and recently, lower electricity sales caused by cooler less humid weather and customer conservation. Absent a responsive final rate order in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate with the current ratings.

HEI and Hawaiian Electric have satisfactory business profiles of '6' and '5', respectively, (business profiles are ranked from '1' (excellent) to '10' (vulnerable)) and somewhat weak financial measures. HEI's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, a currently excellent fuel clause, and relatively steady banking operations. The bank's decent earnings are driven by net interest income from its low-risk earning-asset base, funded largely by a good deposit franchise. These strengths are tempered by Hawaii's economic dependence on a limited number of industries, reliance on fuel oil, significant purchased power obligations, and support of the somewhat riskier banking business. Hawaiian Electric's business profile is slightly stronger than that of the parent due to the absence of nonutility operations.

A responsive final rate order from the Hawaii Public Utilities Commission (PUC) with regard to Hawaiian Electric's pending rate case is crucial to help lift key financial measures to more appropriate levels for the ratings. In September 2005, the PUC issued an interim net rate hike of $41.1 million (3.3%) that is marginally supportive of current ratings. If the amount collected under the interim increase exceeds the amount of the increase ultimately approved in the PUC's final decision and order, the company must refund the excess to its ratepayers with interest. A final order that closely mirrors the interim ruling appears to be sufficient to lift key financial metrics to levels that are marginally suitable for Standard & Poor's guideposts for the 'BBB' rating category. There are no time restrictions in which the PUC must issue a final order. Furthermore, pending before the PUC is HELCO's request for a $29.9 million (9.2%) rate increase. An interim decision is expected in the second quarter of 2007.

Of some concern is Hawaii's Act 162, a new law which appears to confirm, in light of the state legislature's interest in promoting renewable energy, the PUC's ability to authorize the utility's fuel adjustment clause. Although no parties to the rate case seem to oppose the continuation of the clause, a material change to fuel-adjustment mechanism would harm the company's financial condition and detract from its currently satisfactory business profile.

Hawaii's economy grew by about 3.4% in 2005 and is expected to grow by 2.7% in 2006. Military and federal government spending remains strong as the U.S. Department of Defense has moved military assets to Hawaii. Tourism is also a significant component of the Hawaii economy, with visitor days and visitor expenditures up 7.7% and 9.6%, respectively in 2005. Continued growth is expected in 2006, with projected increases of 2.8% in visitor days and 7.1% in visitor expenditures. Although the housing market appears to be stabilizing, the construction industry continues to be healthy. However, future growth in residential construction may slow with rising interest rates. Hawaii's economic growth is expected to be tied primarily to the rate of expansion in the mainland U.S. and Japan economies and increased military spending, yet remains vulnerable to uncertainties in the world's geopolitical environment.

Hawaiian Electric's projected $912 million capital outlays over the next five years will focus predominantly on additions and improvements to transmission and distribution facilities (approximately 51%) and on generation projects (approximately 41%). The balance is for general plant, energy solutions, and customer-choice technologies. Although the bulk of construction expenditures will continue to be funded internally, the company's larger investment in reliability projects will result in increased reliance on outside capital.

HEI has certain bondholder protection metrics that are subpar for the current ratings. In this regard, total debt to capital (adjusted for off-balance-sheet obligations, such as purchased-power contracts and trust-originated preferred securities) and funds from operations (FFO) to total debt are somewhat weak at about 57% and 17%, respectively. Adjusted FFO interest coverage remains healthy at roughly 3.8. Accordingly, a supportive final rate order, tight cost controls, improved earnings, and credit supportive actions by management will be required to lift the company's overall financial profile to more suitable levels.

Short-term credit factors

The short-term corporate credit and commercial paper ratings on HEI and Hawaiian Electric are 'A-2', incorporating solid liquidity, a manageable maturity ladder, and the ability to internally fund a large portion of dividends and capital expenditures in nearby years.

HEI maintains a $100 million unsecured revolving credit facility that expires on March 31, 2011. The covenants require HEI to maintain a nonconsolidated capitalization ratio of 50% or less and consolidated net worth of $850 million. The company is comfortably in compliance with these covenants. HEI used the aforementioned facility to support the issuance of commercial paper to refinance its $100 million of medium-term notes which matured on April 10, 2006. In August 2006, HEI permanently funded the maturity with medium-term notes and terminated a $75 million unsecured bilateral revolver. Effective April 3, 2006, Hawaiian Electric entered into a $175 million revolver that expires on March 29, 2007, but will automatically extend to five years if the longer-term agreement is approved by the PUC. Pursuant to the agreement, the company must maintain a consolidated common stock equity to capitalization ratio of at least 35%, with which the company is in compliance.

Both HEI's and Hawaiian Electric's facilities support the issuance of commercial paper, but may also be drawn for general corporate purposes. Hawaiian Electric's facility may also be drawn for capital expenditures. The facilities do not contain interest coverage ratio requirements, material adverse change clauses, nor rating triggers. As of Oct. 31, 2006, both HEI's and Hawaiian Electric's credit facilities were undrawn.

HEI has a manageable maturity ladder, with just $10 million due in 2007. Hawaiian Electric has no maturing long-term debt until 2012. As of Sept. 30, 2006, HEI had $6.8 million of cash and cash equivalents (excluding American Savings Bank's cash and cash equivalents).

Standard & Poor's expects about three-quarters of Hawaiian Electric's 2006 construction program to be internally funded. Accelerating capital expenditures may necessitate a somewhat higher reliance on outside capital in 2007. In order to strengthen its balance sheet and support its capital program, Hawaiian Electric is not paying dividends to HEI in the second half of 2006. Importantly, ongoing growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows. The decrease in

Hawaiian Electric's dividend to HEI is expected to be partly offset by the increase in the bank's dividend. In the third quarter of 2006 the bank began, and plans to continue, to pay nearly all of its earnings as dividends to HEI while maintaining its target core capital ratio of 7.5% and still supporting its own business growth.

HEI has $50 million of debt capacity remaining under a Rule 415 shelf registration and $96 million remains on an omnibus shelf registration.

Outlook

The negative outlook on Hawaiian Electric mirrors that of parent HEI and reflects a subpar consolidated financial condition relative to the rating level. Failure to strengthen key financial parameters, especially cash flow coverage of debt, a slump in the Hawaiian economy, a punitive final rate order, and, although not expected, a major erosion in American Savings Bank's creditworthiness could lead to lower ratings. Conversely, credit-supportive actions by the company as well as responsive rate treatment would lead to ratings stability.

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STANDARD & POOR'S RATINGSDIRECT

RESEARCH

Industry Report Card: U.S. Utility Second-Quarter Upgrade Surge Is Strongest In Years

Publication date: 10-Jul-2006
Primary Credit Analyst: Richard W Cortright, Jr., New York (1) 212-438-7665; richard_cortright@standardandpoors.com

Commentary/Key Trends

During the second quarter of 2006, the U.S. power sector again saw upward rating momentum that began in the first quarter. Rating actions among electric, gas, pipeline, and water utilities moved in a very positive direction, as Standard & Poor's Ratings Services upgraded three companies (19 individual company ratings) and downgraded just one. Upgrades for the first half of the year totaled nine companies, versus only four downgrades. This starkly contrasts with 2004 and 2005, when rating downgrades outpaced upgrades by about three to two.

Rating upgrades affected two of the biggest diversified energy companies and their subsidiaries, which had suffered significant credit deterioration during the power crisis in the merchant sector in 2002. Ratings on The Williams Companies Inc. were raised to 'BB-' from 'B+', and El Paso Corp. to 'B+' from 'B'. Williams has demonstrated improved financial metrics principally from deleveraging, as well as from improved operating performance, while El Paso has refocused its strategy on its core pipeline and oil and gas exploration and production operations and has stabilized its financial position. The upgrade also incorporated a much-strengthened liquidity position, although refinancing risk remains. Upgrades included one transmission and distribution utility, NSTAR, and its several operating utility subsidiaries, whose ratings were raised to 'A+' from 'A' as the result of an ongoing, constructive regulatory environment and expectations of sustained, strong credit metrics stemming from the recently approved rate agreement. Finally, Northern Border Pipeline Co.'s upgrade to 'A-' from 'BBB+' reflected its changed ownership, which is now shared equally between Northern Border Partners L.P., and a TransCanada PipeLines Ltd. affiliate. The ratings are now viewed on a stand-alone basis, supported by the credit strength of each parent and its low-risk business strategy. The sole downgrade during the quarter was of integrated utility Empire District Electric Co., to 'BBB-' from 'BBB', where continued deferral of fuel and purchased-power costs exceeds the level of allowed recovery. A heavy capital-expenditure program further challenges the company's financial profile.

Unlike the previous quarter, when many ratings actions and outlook revisions could be directly attributed to merger and acquisition (M&A) activity, second-quarter actions were attributable to more organic developments, such as improving financial performance and business strategy revisions. Outlook revisions in the quarter were few, but demonstrated a stable to positive trend. Financial improvement affected the actions on Edison Mission Energy (EME), a merchant company, and IPALCO Enterprises Inc. A simplified business strategy resulted in the outlook revision to positive from stable for Duke Energy Corp., and a revision to stable from CreditWatch negative for ONEOK Inc. The outlooks on two companies, Consolidated Edison Inc. and TXU Corp. (and their subsidiaries), were revised to negative from stable. Respectively, the revisions reflect expectations that financial ratios will deteriorate significantly in 2006, and an ambitious build-out plan of generating facilities. In the case of Black Hills Corp. (and its utility subsidiary), ratings were affirmed with a negative outlook and removed from CreditWatch with negative implications, following the company's withdrawal of an offer to acquire NorthWestern Corp.

Negative outlooks and CreditWatch listings with negative implications remained at about 30% of total outlooks at the end of the second quarter, while about 13% of outlooks are positive or on CreditWatch with positive implications. The majority of ratings outlooks, about 56%, remain stable.

The utility and merchant power sectors' credit quality for the remainder of 2006 and beyond will depend largely on a few significant factors:

- Regulatory rulings regarding post-transition market structures;
- Fuel cost recovery in a high-fuel-price environment;
- M&A activity; and
- The decisions that regulatory commissions must make regarding the approaching end of lengthy rate freezes and industry transition periods in many states.

Rising fuel costs and accelerating capital-spending requirements exacerbate the inherent uncertainty that significant regulatory proceedings entail.

Maryland provides a good example of the challenges that certain utilities face in fuel cost recovery. The political strife that has enveloped the state as a result of a pending 72% electric rate hike by Baltimore Gas & Electric Co. (BGE), following the end of a seven-year rate cap in 2006, represents a possible scenario for what other states could face. Price caps that were established many years ago to ease the transition to market prices are expiring, just as rising fuel costs, particularly for natural gas, have caused electricity prices in wholesale markets to increase dramatically. Regulators and legislators have engaged in a contentious debate over how to moderate massive rate hikes that ratepayers would face in the absence of a change to current law. Based on these political developments in Maryland, Standard & Poor's revised the CreditWatch listing on Constellation Energy Group Inc. to Watch Developing from Watch Positive in the first quarter, to reflect the potential damage to Constellation's consolidated credit quality. In June, Maryland's legislature passed a bill, and overrode the governor's veto of it, that will limit BGE's ability to raise rates by only 15%, and allow the utility to defer fuel costs for recovery beginning in 2008. Standard & Poor's views this legislation as no more than a deferral of a difficult decision, and consequently sustains the threat to Constellation's credit profile. Similar regulatory issues and developments may affect utilities in Illinois, which have negative outlooks or are on CreditWatch with negative implications, due largely to this uncertain climate. These utilities' consolidated financial condition would materially suffer without the ability to recover increased costs for power.

The merchant power saw a fair amount of rating activity in the second quarter. Mirant and NRG were placed on CreditWatch because of the unsolicited bid by Mirant to acquire NRG, both of which only recently emerged from bankruptcy. The CreditWatch listings were removed when Mirant quickly backed away from its bid following NRG's refusal to negotiate. Despite this particular failure, Standard & Poor's expects that other bids in the merchant sector will occur and that a general consolidation will result.

Another significant rating action in the quarter was the outlook revision to positive from stable for EME. Standard & Poor's expects EME's financial position to improve once a proposed tender and refinancing is completed. The proposal eliminates a considerable amount of refinancing risk while adding substantial liquidity.

Chart 1

image

Chart 2

image

Issuer Review

Table 1

Company/Corporate credit rating*/Comment	Analyst
AEP Texas Central Co. (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
AEP Texas North Co. (BBB/Stable/--)	

See American Electric Power Co. Inc. — Todd Shipman

AES Corp. (The) (BB-/Stable/--)

Standard & Poor's Ratings Services expects AES Corp. to continue to reduce parent-level debt and to invest in new projects. We also expect continued strong cash flows from the U.S. subsidiaries Indianapolis Power & Light Co. and AES Eastern Energy LLC, but potential volatility exists from subsidiaries in developing economies such as C.A. La Electricidad De Caracas in Venezuela. We expect monetization of some existing projects and reinvestments in alternative energy. — Aneesh Prabhu

AGL Resources Inc. (A-/Negative/A-2)

AGL Resources Inc. benefited from the strong performance at its asset optimization business Sequent. Through first-quarter 2006, AGL's adjusted funds from operations (FFO) to interest coverage was 4.3x and adjusted FFO to average total debt was 20.2%. Standard & Poor's Ratings Services forecasts adjusted FFO to be between 18% to 21% and leverage to be between 57% to 53% debt to total capitalization, adjusted for operating leases, through 2008. — Ravi Myneni

Alabama Gas Co. (BBB+/Stable/--)

See Energy East Corp. — Brian Janiak

Alabama Power Co. (A/Stable/A-1)

See Southern Co. — Terry Pratt

Allegheny Energy Inc. (BB+/Positive/--)

The company continues to make progress in restoring its financial profile through debt reduction and refinancing. The company expects 2006 pre-tax income to improve from higher provider of last resort rates, participation as a generation supplier in auction markets, from the transition to market-based rates in the deregulated sector of its business, and from the sale of the Ohio territory, tempered by higher coal costs. A recently proposed plan to expand its transmission system could win FERC approval by June 2006 and will cost $1.3 billion. — Aneesh Prabhu

Allegheny Energy Supply Co. LLC (BB+/Positive/--)

See Allegheny Energy Inc. — Aneesh Prabhu

ALLETE Inc. (BBB+/Stable/A-2)

Standard & Poor's Ratings Services expects ALLETE Inc.'s cash flow to be skewed by the timing of a tax rebate in 2006 related to the buyout of the Kendall purchased-power agreement (PPA) in 2005. After normalizing the timing of the tax rebate into 2005, Standard & Poor's forecasts that ALLETE would maintain financial metrics in 2006 consistent with a 'BBB+' rating. The company is likely to achieve interest coverage of about 4.1x and funds from operations to total debt from 20% to 23%. In general, Standard & Poor's views ALLETE's buyout of the Kendall PPA as favorable. — Ravi Myneni

Alliant Energy Corp. (BBB+/Stable/A-2)

Expectations are that Alliant Energy Corp.'s consolidated financial measures will remain consistent with the current ratings over the intermediate term, but this stability depends on successfully selling noncore assets and using at least a portion of the proceeds to reduce debt at Alliant Energy Resources Inc. Although cash flow protection ratios could improve from supportive regulation in the pending Wisconsin base rate case, this may not fully offset the loss of depreciation expense resulting from the sale of the company's interest in Duane Arnold and the imputation of purchased-power-related debt for the Duane Arnold and Kewaunee contracts. — Jeanny Silva

Alliant Energy Resources Inc. (BBB+/Stable/A-2)

See Alliant Energy Corp — Jeanny Silva

Ameren Corp. (BBB+/Watch Neg/A-2)

The CreditWatch listing reflects the aggressive opposition by the Illinois governor and others to the reverse auction process by which Ameren Corp.'s Illinois utilities are expected to procure their power beginning in 2007. Without some form of rate increase phase-in plan, electric rates are expected to increase dramatically in 2007 as rates have been flat to declining for the past 15 to 25 years. There is also significant uncertainty about the outcome of the utilities' pending delivery service rate hike requests totaling $200 million. An Illinois Commerce Commission decision is expected in November 2006. Ameren has noted that the inability to adjust rates to reflect full and timely recovery could, in the extreme, lead to its Illinois utilities filing for bankruptcy. — Barbara Eiseman

AmerenEnergy Generating Co. (BBB+/Watch Neg/--)

See Ameren Corp. — Barbara Eiseman

American Electric Power Co. Inc. (BBB/Stable/A-2)

American Electric Power Co. Inc. (AEP) is faced with an almost constant cycle of regulatory proceedings in one or more of the 11 states in which it operates, as well as at the federal level. Managing such a diverse collection of regulators and the risk it carries is a challenge, even for an organization as large and deep as AEP. The decision by the Texas Public — Todd Shipman

Utilities Commission to cut stranded-cost recovery was a credit disappointment. Second, the mostly coal-based company will be spending a lot of money on environmental compliance for the foreseeable future, which will be a massive undertaking that heightens operating risk and regulatory risk, and threatens AEP's generation cost advantage.

American States Water Co. (A-/Stable/--)

Credit quality reflects that of main subsidiary Golden State Water Co., which recently achieved its strongest financial metrics in more than five years. The regulatory environemnt in California has improved considerably. Nonregulated contract operations remain small in scale, although the company is actively pursuing privatization contracts for military water and wastewater systems. — Michael Scholder

American Transmission Co. (A+/Stable/A-1)

As American Transmission Co. continues its extensive building program over the next 10 years, the company will be challenged to manage transmission construction costs, but Standard & Poor's expects that capital spending will not weaken financial measures while ATC's utility owners continue to support credit quality through equity contributions. If the owners were to curtail equity funding and if debt leverage were to materially increase, credit quality could be affected. Currently, the company's financial measures are strong for the rating, in part because of constructive FERC regulation and reliable operations. — Gerrit Jepsen

American Water Capital Corp. (A-/Watch Neg/--)

The company's ultimate parent, German multiutility RWE AG (A+/Negative/A-1), is in the process of obtaining regulatory approval for the planned spin-off and IPO of American Water, which should be finalized during the second half of 2007. The CreditWatch listing is not expected to be resolved until further detail is known about the company's ownership structure, capital structure, and business plan following the IPO. — Kevin Beicke

ANR Pipeline Co. (B+/Positive/B-3)

See El Paso Corp. — Ben Tsocanos

Appalachian Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Aqua Pennsylvania Inc. (A+/Stable/--)

After having completed seven acquisitions of small water and wastewater systems in the first quarter, parent Aqua America Inc. announced in May that it has reached an agreement to acquire New York Water Service Corp, a midsize water utility in Nassau County, NY, in a transaction valued at $51 million. The company is expected to remain acquisitive to help maintain its above-average growth rate, and will likely continue acquiring one or more medium-to-large water system every couple of years. Consolidated financial performance is expected to remain strong, with adjusted funds from operations (FFO) to total debt around 16% to 18% and adjusted FFO interest coverage greater than 4x. — Kevin Beicke

Aquarion Co. (A/Watch Neg/--)

The ratings on Aquarion Co. and its subsidiaries remain on CreditWatch with negative implications, pending its proposed sale to Maquarie Bank Ltd. The resolution of the CreditWatch listing depends on the financing structure of the transaction, Macquarie's intended business strategy for Aquarion, and regulatory approvals. A credit-conducive financing structure could support Aquarion's current rating. However, a more aggressive financial structure could result in lower ratings. Completion of the regulatory process is expected to occur in the second half of 2006. — Plana Lee

Aquarion Water Co. of Connecticut (A/Watch Neg/--)

See Aquarion Co. — Plana Lee

Aquila Inc. (B-/Watch Pos/B-3)

Aquila Inc. has definitive sales agreements to sell four utilities for an estimated $897 million, which prompted Standard & Poor's Ratings Services to place Aquila on CreditWatch. One sale has already been completed. The utilities contribute $100 million to EBITDA, and proceeds could provide material debt reduction and limit intermediate refinancing risk. Selling the three gas utilities will help reduce the company's working-capital requirements. Due to its speculative-grade status, Aquila must prepay and post collateral on its gas purchases. In an elevated commodity price environment, such prepay and posting requirements can be a significant drain on cash and other liquidity sources. — Jeanny Silva/Todd Shipman

Arizona Public Service Co. (BBB-/Stable/A-3)

See Pinnacle West Capital Corp. — Anne Selting

Atlanta Gas Light Co. (A-/Negative/--)

See AGL Resources Inc. — Ravi Myneni

Atlantic City Electric Co. (BBB+/Watch Neg/A-2)

See PEPCO Holdings Inc. — Gerrit Jepsen

Atmos Energy Corp. (BBB/Stable/A-2)

Funds from operations (FFO) to debt and FFO interest coverage are consistent with the current rating guidelines at 15% and 3.4x, respectively. No rating changes are expected over the next quarter. — Jeffrey Wolinsky

Avista Corp. (BB+/Stable/B-1)

Avista Corp.'s near-term credit quality is expected to be sustained by stable cash flows that, along with the proceeds from its continuous equity issuance, should be adequate to pay down reasonable debt levels and finance Avista's capital program. Positive cash flows support the rating, despite a weak financial risk profile. The company remains vulernerable to poor hydro seasons and volatility, due to its energy trading operations. — Anne Selting

Baltimore Gas & Electric Co. (BBB+/Watch Dev/A-2)

See Constellation Energy Group Inc. — Aneesh Prabhu

Baton Rouge Water Works Co. (The) (AA/Stable/--)

Baton Rouge Water Works Co. continues to maintain strong cash flows and conservative financial management. Capital expenditures are expected to remain elevated in 2006 and 2007, as the company ensures its ability to meet future supply needs in the high-growth Ascension Parrish area, as well as the increase in customers who moved from New Orleans due to the 2005 hurricanes. However, the one-time nature of these construction costs and the company's ability to cover most of these costs internally should negate any detrimental effects. Financial performance is expected to remain robust, led by the company's healthy free operating cash flow, its adjusted funds from operations (FFO) to total debt ratio of greater than 30%, and its adjusted FFO interest coverage of greater than 5.5x. — Kevin Beicke

Bay State Gas Co. (BBB/Stable/--)

See NiSource Inc. — Barbara Eiseman

Black Hills Corp. (BBB-/Negative/--)

Following the withdrawal of its offer to purchase NorthWestern Corp., Black Hills Corp. is expected to return its focus to internal growth projects, such as the construction of the Wygen II power plant and the development of its natural gas and oil reserves. Management's focus on improving the operating performance of its oil and gas business should result in improving credit measures throughout 2006. — Jeanny Silva

Black Hills Power Inc. (BBB-/Negative/--)

See Black Hills Corp. — Jeanny Silva

Boston Edison Co. (A+/Stable/A-1)

See NSTAR — Jeffrey Wolinsky

Boston Gas Co. (A/Watch Neg/--)

See KeySpan Corp. — Jeffrey Wolinsky

California Water Service Co. (A+/Stable/--)

Rating stability is supported by improved financial performance, driven largely by timelier rate relief granted to main subsidiary, California Water Service Co. California Water has taken notable steps to improve its balance sheet with two separate issuances of common stock totaling $77 million since August 2003, reducing debt leverage to about 50%. Capital requirements are high at between $70 million and $80 million per year through 2009. — Michael Scholder

Calpine Construction Finance Co (CCC-/Negative/--)

In late 2005, Standard & Poor's Rating Services lowered its ratings on Calpine Corp. and some of its subsidiaries to 'D' after the company filed for Chapter 11 bankruptcy protection. The ratings on Calpine Construction Finance Co. remain unchanged at 'CCC-', because this entity was excluded from the bankruptcy filing. However, there is a possibility that this entity could be filed in the future. — Swami Venkataraman

Calpine Corp. (D/--/--)

Standard & Poor's Rating Services lowered its ratings on Calpine Corp. and some of its subsidiaries to 'D' after the company filed for Chapter 11 bankruptcy protection. — Swami Venkataraman

Calpine Generating Co (D/--/--)

Standard & Poor's Rating Services lowered its ratings on Calpine Corp. and Calpine Generating Co to 'D' after the company filed for Chapter 11 bankruptcy protection. — Swami Venkataraman

Cambridge Electric Light Co. (A+/Stable/--)

See NSTAR — Jeffrey

Wolinsky

Carolina Power & Light Co. D/B/A as Progress Energy Carolina (BBB/Stable/A-2)

See Progress Energy Inc. — Jodi Hecht

Cascade Natural Gas Corp. (BBB+/Stable/--)

On Feb. 15, 2006, Cascade Natural Gas Corp. filed with the Washington Utilities and Transportation Commission for its first base rate increase in 10 years. In addition, the company requested that the commission approve a "decoupling" mechanism to address the impact of retail sales volatility on fixed cost recovery. Exposure to gas cost volatility is mitigated by purchased gas cost adjustment mechanisms in both Washington and Oregon, although regulatory lag issues can arise due to the build-up of deferred gas costs between adjustment dates. Cash flow coverage remains strong, while debt leverage has declined to favorable levels. — Leo Carrillo

CenterPoint Energy Inc. (BBB/Stable/--)

CenterPoint Energy Inc. is facing two regulatory challenges in the form of a rate case for CenterPoint Energy Houston Electric regarding transmission and distribution rates and from efforts by the Public Utility Commission of Texas to reduce the rate of return related to the company's competition transition charge to recover $596 million over 14 years at 11.075%. Neither challenge is expected to be resolved in the near term. In the intermediate term, CenterPoint's operations should benefit from the diversity and future cash flows from the proposed pipeline projects, including the most recently proposed 1,600 mile pipeline from Waha, Texas to Oakford/Delmont, Pa., which would allow low-cost natural gas to meet high demand in markets in the northeast. — Dimitri Nikas

CenterPoint Energy Resources Corp. (BBB/Stable/--)

See CenterPoint Energy Inc. — Dimitri Nikas

Central Hudson Gas & Electric Corp. (A/Stable/--)

Parent CH Energy Inc.'s $9.8 million majority interest investment in a 19-MW upstate New York biomass electric generating plant during April was the latest unregulated investment. Since the 2001 sale of its generating assets, the parent has been looking to redeploy about $100 million in cash on hand (cash balance $78.5 million at March 31, 2006), combined with up to a similar amount of debt, and apply toward building a portfolio of energy related assets. Central Hudson is in the process of negotiating a settlement of its rate case, with a favorable outcome needed to maintain the utility's modest financial risk profile. — Kevin Beicke

Central Illinois Light Co. (BBB+/Watch Neg/--)

See Ameren Corp. — Barbara Eiseman

Central Illinois Public Service Co. (BBB+/Watch Neg/--)

See Ameren Corp. — Barbara Eiseman

Central Maine Power Co. (BBB+/Stable/A-2)

See Energy East Corp. — Jeffrey Wolinsky

Central Vermont Public Service Corp. (BB+/Stable/--)

Central Vermont Public Service Corp. requested a rate increase of about 6.15% in May, which is a critical part of its strategy to improve ratings. In addition, an appeal of its 2005 rate case decision is pending and a decision could be forthcoming fairly soon. Moreover, management has implemented various cost savings initiatives in order to improve its financial performance. Furthermore, the company has reorganized its Board of Directors to be composed of more individuals from its service territory, which may help its efforts to mend its regulatory relationships. — Andrew Watt

CILCORP Inc. (BBB+/Watch Neg/--)

See Ameren Corp. — Barbara Eiseman

Cincinnati Gas & Electric Co. (BBB/Positive/A-2)

See Duke Energy Corp. — Dimitri Nikas

Cinergy Corp. (BBB/Positive/A-2)

See Duke Energy Corp. — Dimitri Nikas

Cleco Corp. (BBB/Negative/--)

Cleco Corp.'s credit profile may be pressured in the intermediate term as a result of the construction of a 600 MW solid fuel plant to address Cleco Power LLC's capacity shortfall, which is currently met with power purchases.There is — Dimitri Nikas considerable financing and construction risk associated with the project. The company recently increased the size of the credit facilities at Cleco Power to $275 million from $125 million, to ensure sufficient liquidity during construction. In addition, the credit facility maturity was extended by one year to 2011. Cleco's credit profile benefits from regulatory approvals to recover sizable hurricane costs incurred in 2005, but the 10-year term of recovery is lengthy. At the same time, Cleco is striving to operate the Acadia plant on a merchant basis, following the bankruptcy filing by partner and tolling counterparty Calpine Corp.

Cleco Power LLC (BBB/Negative/--)

See Cleco Corp. — Dimitri Nikas

Cleveland Electric Illuminating Co. (BBB/Stable/--)

See FirstEnergy Corp. — Aneesh Prabhu

CMS Energy Corp. (BB/Stable/--)

CMS Energy's significantly improved liquidity position, continued focus on low-risk core utility operations, and significant reduction of parent-level debt over the past few years resulted in the revision of its outlook to stable from negative. Furthermore, CMS maintained adequate liquidity. Nevertheless, Standard & Poor's expects the company to reduce its high leverage to further support the rating profile. — Brian Janiak

Colonial Gas Co. (A/Watch Neg/--)

See KeySpan Corp. — Jeffrey Wolinsky

Colorado Interstate Gas Co. (B+/Positive/B-3)

See El Paso Corp. — Ben Tsocanos

Columbia Energy Group (BBB/Stable/--)

See NiSource Inc. — Barbara Eiseman

Columbus Southern Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Commonwealth Edison Co. (BBB+/Watch Neg/A-2)

See Exelon Corp. — Richard Cortright

Commonwealth Electric Co. (A+/Stable/--)

See NSTAR — Jeffrey Wolinsky

Connecticut Light & Power Co. (BBB/Stable/--)

See Northeast Utilities — Arleen Spangler

Connecticut Natural Gas Corp. (BBB+/Stable/A-2)

See Energy East Corp. — Jeffrey Wolinsky

Connecticut Water Co. (The) (A/Stable/--)

See Connecticut Water Service Inc. — Kevin Beicke

Connecticut Water Service Inc. (A/Stable/--)

Connecticut Water Service Inc.'s earnings should be lower in 2006 due to the sale of the company's Barnstable water operations for $10 million in May 2005. The company's largest regulated water utility, The Connecticut Water Co., plans to file for rate relief this summer. This will be the first rate increase for Connecticut Water Co. in fifteen years, and is driven by increased operating costs in areas such as electricity, wages, pensions, medical, audit, and insurance costs, as well as significant increases in infrastructure investment. The company may be pressured to maintain its modest financial risk profile without proper rate relief. Adjusted funds from operations (FFO) to total debt has weakened to around 15%, but adjusted FFO interest coverage remains adequate at just under 4x. — Kevin Beicke

Consolidated Edison Co. of New York Inc. (A/Negative/A-1)

Standard & Poor's Ratings Services expects that financial ratios will deteriorate significantly in 2006 with funds from — Jeffrey operations (FFO) to total debt dropping to about 10% and FFO interest coverage dropping to 2.7x. We expect the ratios to improve somewhat in 2007 as the existing Consolidated Edison Co. of New York (CECONY) rate increase goes into effect. A significantly greater-than-forecast deterioration in the company's financial ratios could lead to a downgrade. Implicit in the current rating is the expectation that the 2008 CECONY rate increase will be sufficient to improve FFO to debt to about 16% and FFO interest above 3.5x. If the rate increase is not sufficient, ratings could be lowered — Wolinsky

Consolidated Edison Inc. (A/Negative/A-1)

See Consolidated Edison Inc. — Jeffrey Wolinsky

Consolidated Natural Gas Co. (BBB/Stable/A-2)

See Dominion Resources Inc — Aneesh Prabhu

Constellation Energy Group Inc. (BBB+/Watch Dev/A-2)

Stipulations in a recently passed Senate Bill that allows subsidiary Baltimore Gas & Electric Co. full recovery over time but defer recovery of power costs to later years on an unspecified basis could still result in significant rate increases. This would occur if prices set in future supply auctions remain elevated and as customers start paying for balances currently deferred. Importantly, the expulsion of the Maryland Public Service Commission sets a troubling precedent. The potential for a ratings upgrade assumes that the announced merger with higher-rated FPL Co. is consummated and that the combined company will not pursue a more aggressive business strategy or financial policy than each company had pursued individually. The proposed sale of gas-fired assets and use of debt-production proceeds is viewed favorably. — Aneesh Prabhu

Consumers Energy Co. (BB/Stable/B-1)

See CMS Energy Corp. — Todd Shipman

Coral Energy Holdings (A-/Stable/-)

The rating on Coral Energy Holdings continues to reflect the 'AA' rating of its ultimate parent Royal Dutch Shell PLC and the strong potential for parent support given Coral's key role in trading and marketing primarily gas and power for Shell Oil in U.S. markets. Coral's balance sheet and liquidity have strengthened in 2006, with a sizable increase in parent revolving and term credit facilities. Coral's overall financial performance for first-quarter 2006 is much improved from the same period in 2005, though much of this is supported by high gas prices, which could be temporary. — Terry Pratt

CrossCountry Energy LLC (BBB/Stable/--)

The ratings on CrossCountry Energy LLC benefit from cash flows from wholly owned subsidiary Transwestern Pipeline Co. LLC combined with dividends from 50%-owned subsidiary Citrus Corp. (parent to Florida Gas Transmission Co.). Transwestern's San Juan lateral has been placed in service, adding 375 million cubic feet per day of capacity, which was favorable for credit quality. However, Transwestern is also contemplating a new lateral off of its main line into the Phoenix market, and aggressive financing for the expansion could strain the ratings. — Plana Lee

Dayton Power & Light Co. (BB/Positive/--)

See DPL Inc. — Todd Shipman

Delmarva Power & Light Co. (BBB+/Watch Neg/A-2)

See PEPCO Holdings Inc. — Gerrit Jepsen

Detroit Edison Co. (BBB/Stable/A-2)

See DTE Energy Co. — Todd Shipman

Dominion Resources Inc. (BBB/Stable/A-2)

Dominion Resources Inc.'s performance may be negatively affected in 2006 from higher unrecoverable fuel costs at Virginia Power Co., but lower gas prices and a mild winter have mitigated fuel-related losses. Lost exploration and production (E&P) production from weather events has largely returned. Even so, risks to E&P cash flow could arise from service cost pressures. Recent changes in Virginia legislation reduce the need for E&P to act as a natural hedge for utility fuel costs. As a result, an ongoing asset review will likely determine future strategy. Hedging policy remains intact and Dominion added significant incremental hedges. Liquidity concerns have receded with gas prices at a more sustainable level. Free cash flow is expected to stay negative in 2006 and hinder any upward ratings momentum until it becomes sustainable. — Aneesh Prabhu

DPL Inc. (BB/Positive/--)

The sale of a sizable portion of DPL Inc.'s higher-risk investment portfolio, combined with the company plans to use such cash proceeds toward debt reduction, bolsters DPL's overall creditworthiness by enhancing its business profile and should further improve its financial profile. The positive outlook incorporates new management's sustained commitment to reconcile the company's former weak internal controls and corporate governance issues, combined with the utility generating sufficient cash flow and further reduction of DPL's consolidated debt leverage. Future upward momentum for DPL's credit ratings will be strongly correlated with the actual timing of the sale of its remaining interest of its investment — Brian Janiak portfolio assets and management's ultimate use of cash proceeds toward the balancing of debt reduction and reinvestment needs in its core operations.

DTE Energy Co. (BBB/Stable/A-2)	
The implementation of a Michigan Public Service Commission-authorized transition charge has helped to slow sales losses from the customer choice program in first-quarter 2006. However, the commission is considering a rate decrease that could erode the company's financial profile below a level consistent with current ratings. The stable outlook on DTE Energy Co. is based in part in advancing a constructive regulatory agenda. Also, synthetic fuel operations were expected to generate about one third of total cash flow in 2006, but high oil prices could cut into that forecast.	Todd Shipman
Duke Capital LLC (BBB/Positive/A-2)	
See Duke Energy Corp.	Dimitri Nikas
Duke Energy Corp. (BBB/Positive/--)	
The credit profile of Duke Energy Corp. may improve if the company successfully and timely sells Cinergy Corp.'s trading and marketing operations. On the completion of the sale, Duke Energy's main nonregulated activities will consist of real estate operations and a small international presence, leading to a business risk profile significantly different from even the beginning of 2006. In addition, while the company is contemplating the potential separation of the electric and natural gas assets, no material detail is available on how this approach may be pursued. However, if separation occur it is highly likely to be in a credit neutral manner.	Dimitri Nikas
Duke Energy Trading and Marketing LLC (BBB-/Stable/--)	
See Duke Energy Corp.	Dimitri Nikas
Duke Power Company LLC (BBB/Positive/A-2)	
See Duke Energy Corp.	Dimitri Nikas
Duquesne Light Co. (BBB/Negative/--)	
See Duquesne Light Holdings Inc.	Gerrit Jepsen
Duquesne Light Holdings Inc. (BBB/Negative/--)	
Standard & Poor's Ratings Services continues to focus on the company's acquisition of ownership interests in two coal plants, a pending rate case, and the financial performance of a portfolio of nonutility businesses. To maintain current ratings, Duquesne Light Holdings Inc. must maintain a balanced capital structure during the high capital spending by the utility and the acquisition of the plants. Moreover, cash flow should remain strong and in line with our expectations.	Gerrit Jepsen
Dynegy Holdings Inc. (B/Stable/--)	
See Dynegy Inc.	Swami Venkataraman
Dynegy Inc. (B/Stable/--)	
Dynegy Inc. emerged in 2006 as a pure merchant generating company, and its business profile remains vulnerable. Dynegy's tender of its second-priority lein securities will reduce the amount of priority obligations that stand before its senior unsecured debt and has facilitated a one-notch upgrade in those securities. Standard & Poor's Ratings Services will continue to focus on spark spreads and margins in the Midwest and Northeast, which now represent about 80% of Dynegy's business.	Swami Venkataraman
Edison International (BBB/Stable/--)	
Edison International remains debt free following its 2004 retirement of all of its debt. We expect that credit quality will continue to be principally dependent on the creditworthiness of regulated utility subsidiary, Southern California Edison Co. Edison Capital's contributions to the consolidated entity are about one-tenth of the utility's, and Edison Mission Energy Holding and its subsidiaries have not declared dividends. Importantly, Edison International requires the Edison Mission Energy Holding companies to be self-supporting and does not provide them with capital which allows ratings to be separated. A departure from this practice could have negative rating implications for Edison International, Southern California Edison, and Edison Capital.	David Bodek
Edison Mission Energy (B+/Positive/--)	
In first-quarter 2006, Edison Mission Energy's (EME) plants operated well with average availability factors and higher power prices. This resulted in higher cash flow and slightly improved credit metrics. The company remains exposed to volatility in its cash flow, given the reliance on merchant-based cash flow. In April 2006, EME completed a tender offer for $1 billion of outstanding bonds and refinanced those bonds with new bonds at a slightly lower interest rate, but with extended maturities. In addition, EME successfully closed a new $500 million revolving credit facility that provides liquidity for working-capital purposes, as well as collateral posting requirements under hedging transactions. The refinancing evens out the maturity schedule and lessens the refinancing risk for EME. The ratings will likely not change until the EME Holding Company debt is repaid in 2008.	David Bodek
Edison Mission Marketing and Trading (B+/Positive/--)	

Edison Mission Marketing and Trading is rated on a consolidated basis with Edison Mission Energy. Trading and marketing activities are largely restricted to hedging activities for coal-fired generation.	David Bodek
El Paso Corp. (B+/Positive/B-3)	
Ratings on El Paso Corp were raised this past May, recognizing that the company has firmed up its once precarious liquidity, made considerable progress exiting noncore businesses, and stabilized the performance of the exploration and production (E&P) segment. The company completed an expected $500 million equity issuance, the proceeds of which repaid debt incurred to make an E&P acquisition. By selling peripheral businesses, including merchant power and trading, El Paso has reduced demands on liquidity ahead of significant looming debt maturities. Additional ratings improvement is possible in the near term, if the company continues to reduce debt and focus on the core pipeline and E&P businesses.	Ben Tsocanos
El Paso Electric Co. (BBB/Stable/--)	
In 2007, El Paso Electric Co. will be obliged to negotiate an arrangement with Las Cruces, N.M., which accounts for about 28% of revenue, to extend its power supply and delivery business with the city. In 2005, El Paso Electric replaced all remaining secured debt with unsecured debt, which will reduce the cost and simplify the process of separating the business into their component parts of supply and transmission/distribution if and when retail electric competition comes to El Paso Electric's service territory.	Chinelo Chidozie
El Paso Natural Gas Co. (B+/Positive/B-3)	
See El Paso Corp.	Ben Tsocanos
Empire District Electric Co. (BBB-/Stable/A-3)	
Standard & Poor's Ratings Services continues to monitor Empire District Electric Co.'s financial performance during its construction program and gas utility acquisition. In the near term, we will monitor regulatory actions and their effects, if any, on Empire's financial measures or if the financial measures weaken from increased capital spending or higher than expected use of leverage over the next several years.	Gerrit Jepsen
Energen Corp. (BBB+/Stable/--)	
Energen Corp.'s growth strategy continues to focus on expanding the company's oil and gas operations through acquisitions, the most recent of which the company financed with 70% debt. With oil and gas prices at a cyclical high over the last two years, the company's exploration and production operations have helped boost consolidated cash flows. However, the company is increasingly exposed to cyclical pressures. Increased business risk could lead to lower ratings.	Brian Janiak
Energy East Corp. (BBB+/Stable/A-2)	
Although we expect credit measures to improve over the intermediate term with the use of Ginna sale proceeds to reduce debt, a recent administrative law judge decision on the New York State Electric & Gas Corp. (NYSEG) rate filing detracts from credit. A move to a positive outlook is unlikely in the near term, given the current financial forecast and issues associated with the NYSEG rate filing. Significantly lower operating cash, or an unfavorable resolution to the NYSEG rate filing could cause an outlook revision to negative.	Jeffrey Wolinsky
Enogex Inc. (BBB+/Stable/--)	
See OGE Energy Corp.	Jeanny Silva
Entergy Arkansas Inc. (BBB/Watch Neg/--)	
See Entergy Corp.	Dimitri Nikas
Entergy Corp. (BBB/Watch Neg/--)	
Entergy Corp.'s storm-restoration cost estimate is $1.5 billion. Progress for recovery of costs is slow; however, the passage of a securitization bill in Louisiana is considered supportive of the utility's efforts. As of March 31, 2006, Entergy had $752 million of cash on hand and $2.8 billion of borrowing capacity on its $3.7 billion of aggregate credit facilities.	Dimitri Nikas
Entergy Gulf States Inc. (BBB/Watch Neg/--)	
See Entergy Corp.	Dimitri Nikas
Entergy Louisiana Inc. (BBB/Watch Neg/--)	
See Entergy Corp.	Dimitri Nikas
Entergy Mississippi Inc. (BBB/Watch Neg/--)	
See Entergy Corp.	Dimitri Nikas
Entergy New Orleans Inc. (D/--/--)	
See Entergy Corp.	Dimitri Nikas

E.ON US (BBB+/Stable/--)

E.ON US's two utilities in Kentucky are good performers, with low costs, a reasonable regulatory environment, and high customer satisfaction ratings. Capital spending will be a priority for the next few years as environmental compliance upgrades and the new capacity requirements will burden the utilities with large cash needs. Parent company E.ON AG continues to back up its support for LG&E Energy, which is important for ratings stability. — Todd Shipman

E.ON US Capital (BBB+/Stable/A-2)

See E.ON US — Todd Shipman

Equitable Resources Inc. (A-/Watch Neg/A-2)

The company's increasing focus on, and exposure to, the riskier exploration and production (E&P) business challenges credit quality by increasing the need to maintain stronger financial measures due to its higher-risk business profile. The company's recent sale of its interest in Kerr-McGee Corp. ($240 million after tax), the sale of some of its E&P properties, and anounced plans to sell its Noresco energy services business should provide the company with additional proceeds to either reduce debt borrowings or reinvest in its core operations. — Brian Janiak

Exelon Corp. (BBB+/Watch Neg/A-2)

Exelon Corp. received merger approval from the Department of Justice in June, but still awaits decisions by the NRC and the New Jersey Board of Public Utilities. Exelon and Public Service Enterprise Group have expressed their commitment to the merger, which they expect to close in third-quarter 2006. The company's nuclear plant performance remains strong, despite the tritium leakage issue at the Braidwood station. In May, 2006 Exelon subsidiary Commonwealth Edison Co. filed a proposal to ease the effect of the January 2007 rate increases by capping rates for three years and then recovering any excess cost over a subsequent three-year period. — Richard Cortright

Exelon Generation Co. LLC (BBB+/Watch Neg/A-2)

See Exelon Corp. — Richard Cortright

FirstEnergy Corp. (BBB/Stable/--)

The company's rate certainity plan in Ohio will lower cash flow in the near term, but is viewed as credit neutral as it preserves the recovery of increased fuel costs in the post-2008 period. The company's operating performance has been satisfactory, but risks include sustainability of nuclear operations. Rate cases in Pennsylvania and the post-2008 markets structure in Ohio are other risks. Due to higher maintenance expenditures, projected free cash flow will be lower in 2006. Yet, financial metrics and liquidity have improved substantially, as almost $700 million of net debt was paid down in 2005. A share repurchase program could be proposed once the nuclear facilities exit outages and as environmental spending is finalized. — Aneesh Prabhu

Florida Gas Transmission Co. (BBB+/Stable/--)

The ratings on Florida Gas Transmission (FGT) continue to benefit from FERC regulation that is favorable for credit quality, the recent completion of large expansion projects, and concurrent reduction in external borrowing needs. FGT is currently planning its Phase VII expansion, which is expected to be relatively moderate in scale at an estimated capital cost of $80 million. FGT faces increasing competition from Gulfstream Natural Gas System, a joint venture of The Williams Cos. Inc. and Duke Energy Corp. However, FGT maintains the competitive advantage of its incumbent status. — Plana Lee

Florida Power & Light Co. (A/Watch Neg/A-1)

See FPL Group Inc. — Jodi Hecht

Florida Power Corp. D/B/A Progress Energy Florida (BBB/Stable/A-2)

See Progress Energy Inc. — Jodi Hecht

Florida Progress Corp. (BBB/Stable/A-2)

See Progress Energy Inc. — Jodi Hecht

FPL Group Capital Inc. (A/Watch Neg/A-1)

See FPL Group Inc. — Jodi Hecht

FPL Group Inc. (A/Watch Neg/--)

The rating on FPL Group Inc. is on CreditWatch because of its announced merger with Constellation Energy Inc. If the transaction is completed as announced, the combination would likely have a higher business-risk profile and weaker financial profile. The short-term credit focus for FPL Group is the unusually high short-term debt balance, totaling $1.3 billion as of March 31, 2006. The majority of the debt was used to fund storm and under-recovered fuel costs at the utility, FP&L. We expect those balances to decline as the company issues medium- and long-term debt, whose maturities will match the expected cost recovery. — Jodi Hecht

Georgia Power Co. (A/Stable/A-1)

See Southern Co. — Terry Pratt

Golden State Water Co. (A-/Stable/--)

See American States Water Co. — Michael Scholder

Great Plains Energy Inc. (BBB/Stable/--)

Regulated subsidiary Kansas City Power & Light Co. (KCP&L) has begun a large $1.3 billion capital plan that includes a 465-MW investment in a new 850-MW coal-fired generating station at the utility's latan 2 site in Missouri, as well as 100 MW of wind generation. KCP&L filed in February 2006 its first retail rate increase requests with the Missouri and Kansas state regulatory commissions in 20 years. Great Plains Energy Inv. issued about $121 million in common stock in May 2006, and expects to generate an additional $47 million in proceeds by May 2007 under a common stock forward sale agreement with Merrill Lynch Financial Markets Inc. Great Plains Energy Inc.'s retail marketing subsidiary, Strategic Energy, has experienced lower gross margins due to higher market prices, although an evolving product mix and recent market price declines could stabilize performance. Company cash flow coverage is strong, while debt leverage is moderate. — Jeanny Silva

Green Mountain Power Corp. (BBB/Watch Pos/--)

The ratings were placed on CreditWatch on June 22, 2006, following an announcement by a subsidiary of Gaz Metro Inc. (A-/Negative/--) of its agreement to acquire Green Mountain Power Corp. The CreditWatch placement reflects the possibility that Green Mountain Power's credit profile may improve as a result its affiliation with a stronger entity. — Andrew Watt

Gulf Power Co. (A/Stable/--)

See Southern Co. — Terry Pratt

Hawaiian Electric Co. Inc. (BBB+/Negative/A-2)

See Hawaiian Electric Industries Inc. — Barbara Eiseman

Hawaiian Electric Industries Inc. (BBB/Negative/A-2)

The company's consolidated financial metrics are pressured due to rising operating and maintenance expenses, increasing capital outlays, and the prolonged lack of rate relief. An interim net rate increase of $41.1 million (3.3%) is currently in effect for subsidiary Hawaiian Electric Co., and a final rate order that closely mirrors the interim ruling will likely be sufficient to lift key financial parameters to levels that are marginally suitable for the 'BBB' rating. With pending changes in the makeup of the Hawaii Public Utilities Commission, Standard & Poor's Ratings Services expects a decision to be rendered in the very near future. — Barbara Eiseman

Houston Electric LLC (BBB/Stable/--)

See CenterPoint Energy Inc. — Dimitri Nikas

IDACORP Inc. (BBB+/Negative/A-2)

With expected future benefits from rate increases and deferred cost recovery, IDACORP Inc.'s financial ratios are expected to improve to levels commensurate with its 'BBB+' rating. IDACORP has more than $720 million in capital requirements in the next three years, but external funding needs are expected to be modest. Downward rating pressure is possible if financial ratios fail to recover. Two key issues that would determine future ratings movement are water flows in the Snake River and rulings by the Idaho Public Utilities Commission, especially for cost recoveries relating to any aquifer recharge programs and the final treatment and allocation of previous federal and state tax refunds of about $75 million. — Michael Scholder

Idaho Power Co. (BBB+/Negative/A-2)

Seee IDACORP Inc. — Michael Scholder

Illinois Power Co. (BBB+/Watch Neg/--)

See Ameren Corp. — Barbara Eiseman

Indiana Gas Co. Inc. (A-/Stable/--)

See Vectren Corp. — Elif Acar

Indiana Michigan Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Indianapolis Power & Light Co. (BB+/Positive/--)

See IPALCO Enterprises Inc. — Barbara Eiseman

International Transmission Co. (BBB/Watch Neg/--)

See ITC Holdings Corp. — Gerrit Jepsen

Interstate Power & Light Co. (BBB+/Stable/A-2)

See Alliant Energy Corp — Jeanny Silva

IPALCO Enterprises Inc. (BB+/Positive/--)

The ratings on IPALCO Enterprises Inc. are linked to those of parent AES Corp. On June 5, 2006, Standard & Poor's Ratings Services revised the outlook on IPALCO Enterprises Inc. and its subsidiary Indianapolis Power & Light Co. to positive from stable to reflect Standard & Poor's expectations that certain key consolidated financial metrics should strengthen sufficiently over the next several years to support investment-grade ratings. The prospective improvement can be traced to lower than originally expected environmentally-related capital expenditures and reduced external financing needs, supportive ratemaking treatment for such outlays, effective cost controls, and IPALCO's management strategy to reduce dividends paid to parent AES in years with high internal cash needs. — Barbara Eiseman

Iroquois Gas Transmission System L.P. (BBB+/Stable/--)

The company is substantially contracted for firm ship-or-pay contracts under a competitive tariff through 2011, with a diverse basket of financially strong shippers. The pipeline system has a good operating history. A major expansion of the pipeline into New York City has enhanced the system, but encountered construction problems and delays that hurt credit quality. The issue is now largely behind Iroquois Gas. — Todd Shipman

ITC Holdings Corp. (BBB/Watch Neg/--)

The CreditWatch listing reflects Standard & Poor's Ratings Services' view that based on current information on the proposed financing of ITC Holdings Corp.'s acquisition of Michigan Electric Transmission Company LLC (METC), ITC's ratings will either be affirmed or lowered. In addition, the weaker credit quality of Consumers Energy, which is METC's largest counterparty and source of its network revenue, could negatively affect the overall creditworthiness of ITC Holdings. This could be mitigated by the increased diversity of the customer base. — Gerrit Jepsen

Jersey Central Power & Light Co. (BBB/Stable/--)

See FirstEnergy Corp. — Aneesh Prabhu

Kansas Gas & Electric Co. (BB+/Positive/--)

See Westar Energy Inc. — Barbara Eiseman

Kansas City Power & Light Co. (BBB/Stable/A-2)

See Great Plains Energy Inc. — Jeanny Silva

Kentucky Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Kentucky Utilities Co. (BBB+/Stable/A-2)

See E.ON US — Todd Shipman

KeySpan Corp. (A/Watch Neg/A-1)

The ratings on KeySpan Corp. and its subsidiaries are on CreditWatch with negative implications, as a result of the company's agreement to be acquired by National Grid PLC (A/Watch Neg/A-1). If the transaction is funded on an all-cash basis, there is a strong likelihood that the ratings on all the companies will be lowered by one notch. — Jeffrey Wolinsky

KeySpan Energy Delivery Long Island (A+/Watch Neg/--)

See KeySpan Corp. — Jeffrey Wolinsky

KeySpan Energy Delivery New York (A+/Watch Neg/--)

See KeySpan Corp. — Jeffrey Wolinsky

KeySpan Generation LLC (A/Watch Neg/--)

See KeySpan Corp. — Jeffrey Wolinsky

Kinder Morgan Inc. (BBB/Watch Neg/A-2)

The proposed management buyout of Kinder Morgan Inc. would severely impair its credit quality through a massive amount of new debt to be used in the transaction. Persistent questions about operational capabilities and management attention to safety and pipeline integrity requirements add to the pressure on ratings.. — Todd Shipman

Laclede Gas Co. (A/Stable/A-1)

See Laclede Group Inc. — Barbara Eiseman

Laclede Group Inc. (The) (A/Stable/--)

Laclede Group Inc.'s measures of bondholder protection are somewhat weak, but should gradually strengthen due to the implementation of a modest net rate increase of about $4 million in the fall of 2005, weather-mitigation rate design, cost-containment initiatives and operational efficiencies, a gas supply incentive plan, the issuance of new shares of stock under Laclede's dividend reinvestment plan, and expectations for increased profits from the companys' unregulated ventures. The rate order preserved essential ratemaking principles, such as retention of profits from off-system sales (with sharing above $12 million) and the gas supply incentive plan. These factors are expected to help lift and sustain key financial metrics to within Standard & Poor's guideposts for the 'A' rating category. — Barbara Eiseman

Louisville Gas & Electric Co. (BBB+/Stable/A-2)

See E.ON US — Todd Shipman

Madison Gas & Electric Co. (AA-/Stable/A-1+)

The company's capital-spending program, including funds for a small ownership interest in two 615 MW coal units being built in Wisconsin, will be partly funded with internal cash flow, and external financing must be prudent to maintain the company's credit profile and access to capital. In addition, Madison Gas & Electric Co. will continue to require very supportive regulation during this construction cycle to maintain its existing financial risk profile. — Gerrit Jepsen

Massachusetts Electric Co. (A/Watch Neg/A-1)

See National Grid USA — Ravi Myneni

MDU Resources Group Inc. (BBB+/Stable/A-2)

Near-term earnings are expected to be supported by the continued strong natural gas and crude oil prices received by Fidelity Exploration, MDU Resources Group Inc.'s exploration and production subsidiary. In addition, MDU should see improved earnings from its Knife River construction materials subsidiary, supported by a solid business backlog. MDU is expected to continue to make opportunistic acquisitions in its nonregulated businesses, which will be funded in a manner that does not cause deterioration of its balance sheet strength. — Paul Harvey

Metropolitan Edison Co. (BBB/Stable/--)

See FirstEnergy Corp. — Aneesh Prabhu

Michigan Consolidated Gas Co. (BBB/Stable/A-2)

See DTE Energy Co. — John Kennedy

MidAmerican Energy Co. (A-/Stable/A-1)

Standard & Poor's Ratings Services expects continued stable performance from MidAmerican Energy Co. The company's construction of a coal plant is expected to be completed in 2007, and it has completed 360 MW of wind generation. The company's rate settlement agreement extends through Dec. 31, 2011, but does not incorporate a fuel adjustment clause, which may be problematic given increasing fuel costs. This is mitigated by the company's ability to request a rate increase, if the actual earned ROE's in Iowa fall below 10%. — Swami Venkataraman

MidAmerican Energy Holdings Co. (A-/Stable/--)

The ratings on MidAmerican Energy Holdings Co. (MEHC) reflect benefits from its status as a majority-owned subsidiary of Berkshire-Hathaway, Inc. (AAA/Stable) and a $5 billion equity commitment facility that Standard & Poor's expects would be called on to support the rating, if necessary. If Standard & Poor's view of Berkshire's commitment to MEHC changes, the rating could also change. Integration of, and performance at, recently acquired PacifiCorp will be the key management focus over the next few years. MEHC continues to look for investment opportunities, which would likely be funded in large part by equity from Berkshire Hathaway. — Swami Venkataraman

Mid-Atlantic Power Holdings LLC (B/Negative/B-3)

See Reliant Energy Inc. — Dimitri Nikas

Middlesex Water Co. (A-/Stable/--)

Middlesex Water Co. has continued heavy capital-spending needs at subdisiary Tidewater Utilities Inc. and regulatory uncertainty surrounding new wastewater operations at Tidewater Environmental Services Inc. (TESI). Tidewater continues to spend heavily on capital-expenditure needs, to meet customer growth, but its regulatory environment appears to have stabilized. Regulatory treatment for TESI, which is also expected to be capital-intensive, remains — Plana Lee uncertain given recently passed legislation in Delaware regarding regulating wastewater facilities.

Midwest Independent System Operator (MISO) (A+/Stable/--)

The expected withdrawal from the Midwest Independent Transmission System Operator Inc. by Louisville Gas & Electric Co. (LG&E) and Kentucky Utilities Co. (KU) does not affect the rating on MISO, because LG&E and KU are required to pay a lump sum exit fee that MISO would use over time to cover the financial obligations related to the utilities' participation in MISO, including interest and principal payments on debt. Nevertheless, a large exodus of higher-load members could introduce financial risk because remaining MISO's members would be required to pay for a greater share of costs for operations, financing, and capital expenditures. — Gerrit Jepsen

Mirant Americas Generating LLC (B+/Stable/--)

See Mirant Corp. — Terry Pratt

Mirant Corp. (B+/Stable/--)

Mirant Corp.'s withdrawal of its unsolicited bid to acquire NRG Energy Inc. does not affect ratings. The rating factors in the potential for aggressive acquisitions, but those in the future that reduce the large cash balances and result in large amounts of additional debt could lead to a ratings downgrade. Favorably, Mirant's annual cash flow should rise by about $30 to $40 million per year following its settlement of litigation with PEPCO related to out of market Panda-Brandywine purchased-power agreement, for $70 million in cash and $450 million in stock. Cash flow should also rise with recent Department of Energy and Environmental Protection Agency directives allowing the company to increase output of the Potomac River plant. — Terry Pratt

Mirant Mid-Atlantic LLC (BB/Stable/--)

See Mirant Corp. — Terry Pratt

Mirant North America LLC (B+/Stable/--)

See Mirant Corp. — Terry Pratt

Mississippi Power Co. (A/Stable/A-1)

See Southern Co. — Terry Pratt

Montana-Dakota Utilities Co. (BBB+/Stable/--)

See MDU Resources Inc. — Paul Harvey

Monongahela Power Co. (BB+/Positive/--)

See Allegheny Energy Inc. — Aneesh Prabhu

Narragansett Electric Co. (A/Watch Neg/A-1)

See National Grid USA — Ravi Myneni

National Fuel Gas Co. (BBB+/Stable/A-2)

National Fuel Gas Co. has submitted a rate case agreement with the New York Public Service Commission. If approved, the rate increase of $21 million would be the first since 1998. This follows a $12 million rate settlement for its Pennsylvania distribution business which was approved in March. National Fuel Gas will be expanding its Empire State Pipeline, which should help bolster the company's business profile given its strategic location in a capacity-constrained region. Furthermore, Standard & Poor's Ratings Services expects the company's refocused exploration and production strategy to bolster the financial profile. — Brian Janiak

National Grid USA (A/Watch Neg/A-1)

The ratings of National Grid USA remain on CreditWatch, following the announcement by parent, National Grid PLC, to buy U.S. gas distributor KeySpan Corp. (A/Watch Neg/A-1) for GBP 4.2 billion plus assumed debt. Standard & Poor's anticipates lowering ratings on National Grid by one notch, if the acquisition takes place. — Ravi Myneni

Nevada Power Co. (B+/Positive/--)

See Sierra Pacific Resources — Swami Venkataraman

New England Power Co. (A/Watch Neg/A-1)

See National Grid USA — Ravi Myneni

New Jersey Natural Gas Co. (A+/Negative/A-1)

On June 19, 2006, Standard & Poor's Ratings Services affirmed its ratings on New Jersey Natural Gas Co. and revised the outlook to negative due to the greater risk of increased unregulated activities at parent New Jersey Resources Corp. — Plana Lee

(NJR). Ratings stability could be acheived through a combination of factors, including a greater focus on regulated investments, continued strong credit metrics, and prudently financed growth projects. Conversely, a downgrade could result from a continued increase in the proportion of unregulated activities at parent NJR and related liquidity demands.

New York State Electric & Gas Corp. (BBB+/Stable/A-2)

See Energy East Corp. — Jeffrey Wolinsky

New York Water Service Corp. (BB/Watch Pos/--)

The ratings on New York Water Service Corp. are on CreditWatch with positive implications due to the May announcement that regulated water utility Aqua America Inc. has reached an agreement with Utilities & Industries Management Corp. (U&I) to acquire the utility. The 'BB' corporate credit rating on New York Water reflects the aggressive financial risk profile and weak business risk profile of New York Water's unrated parent company, U&I. On a consolidated basis, adjusted funds from operations (FFO) to total debt is about 10% and adjusted FFO interest coverage was just slightly greater than 2x. — Kevin Beicke

Niagara Mohawk Power Corp. (A/Watch Neg/--)

See National Grid USA — Ravi Myneni

Nicor Gas Co. (AA/Negative/A-1+)

See Nicor Inc. — Barbara Eiseman

Nicor Inc. (AA/Negative/A-1+)

In late March 2006, the Illinois Commerce Commission issued a rehearing decision in Nicor Gas Co.'s rate case, decreasing annual base rates modestly, to $49.7 million from $54.2 million. However, because the order shifted certain revenues between base rates and the uniform purchased-gas adjustment clause, the company estimates that the actual net revenue increase will be about $30.2 million versus $34.7 million under the previous order. Nicor Gas and certain other parties have appealed the order to the Illinois appellate courts. Overall, the rate hike supports consolidated financial measures, but may be insufficient to sustain current ratings given the potential for penalties related to alleged abuses of the company's performance-based rate plan and a possible civil injunction. Although Standard & Poor's Ratings Services expects that resolution of outstanding matters will only nominally affect Nicor's financial condition, a severe financial penalty may push certain key financial parameters out of an acceptable range for the mid 'AA' rating. — Barbara Eiseman

NiSource Inc. (BBB/Stable/--)

Certain consolidated bondholder protection parameters are subpar for the ratings, due to pipeline recontracting at somewhat lower rates, increased sharing of offsystem sales and capacity release proceeds in Ohio, and increased losses at the Whiting Clean Energy project due to planned maintenance. Moreover, currently unrecoverable costs associated with the Midwest Independent System Operator and lower customer usage as a result of higher gas prices offset the benefits of sales of short-term services in the company's gas transportation and storage business, growth in the electric business, and a decrease in interest expense in first-quarter 2006. Prospectively, effective cost containment, including an outsourcing agreement with IBM, lower interest expense, enhanced productivity, and the potential for increased sales volumes and possible earnings growth from several planned projects should help bring the company's financial measures up to more appropriate levels in the intermediate term. — Barbara Eiseman

North Shore Gas Co. (A-/Negative/A-2)

See Peoples Energy Corp. — Elif Acar

Northeast Generation Co. (B+/Developing/--)

See Northeast Utilities — Arleen Spangler

Northeast Utilities (BBB/Stable/--)

First-quarter 2006 results for Northeast Utilities were as expected with funds from operations to total interest coverage at 2.4x and FFO to total debt at 10%. Standard & Poor's Ratings Services views the credit-protection measures for NU as weak for the current rating level and expects the measures to remain weak until the costs of a major construction program are recovered in rates in late 2007 or early 2008. Furthermore, although NU has announced its intention to its unregulated operations, it is still subject to execution risk regarding the sale and remains exposed to the risks of those businesses until a sale is completed. Standard & Poor's expects that the exit from the unregulated businesses will improve NU's business profile. — Arleen Spangler

Northern Border Pipeline Co. (A-/Stable/--)

Standard & Poor's Ratings Services raised its corporate credit rating on Northern Border Pipeline Co. (NBPL) to 'A-' from 'BBB+' primarily to reflect its changed ownership, which is now shared equally between ONEOK Partners and a TransCanada Pipelines affiliate. The ratings on NBPL are therefore viewed on a stand-alone basis, supported by the credit strength of each parent and the low-risk business strategy that NBPL employs. Continued ratings stability depends on the company's ability to manage the outcome of its rate case and recontracting risk, given flattening suppies due to — Plana Lee increased natural gas demand within Canada for oil sands development.

Northern Indiana Public Service Co. (BBB/Stable/--)

See NiSource Inc. — Barbara Eiseman

Northern Natural Gas Co. (A/Stable/--)

The rating on Northern Natural Gas Co. was upgraded to 'A' from 'A-'. Structural ring-fencing provisions allow for a ratings separation from parent MidAmerican Holdings Co. The overhang of a pending rate case has been removed as a settlement was reached, and substantial recontract risk has been removed with long-term extensions with Minnesota Gas and Northern States Power – Minnesota. — Swami Venkataraman

Northern States Power Co. (BBB/Stable/A-2)

See Xcel Energy Inc. — David Bodek

Northern States Power Wisconsin (BBB+/Stable/--)

See Xcel Energy Inc. — David Bodek

Northwest Natural Gas Co. (AA-/Stable/A-1)

The ratings on Northwest Natural Gas Co. were raised in February 2006 due to strong sustained financial performance and an excellent business risk profile. The company has a conservative hedging policy, and cash flows are expected to remain solid. Debt to capitalization improved slightly, primarily due to lower commercial paper balances at the end of the winter cooling season. The company continues to invest in nonregulated interstate gas storage business, but converts storage to core customers as needed. — Michael Scholder

Northwest Pipeline Corp. (BB-/Positive/--)

See Williams Cos. — Jeffrey Wolinsky

NorthWestern Corp. (BB+/Watch Neg/--)

Standard & Poor's Ratings Services revised its CreditWatch listing on NorthWestern Corp. after the announcement that Babcock & Brown Infrastructure Ltd. (BBI) will acquire the company for $2.2 billion with $505 million of new debt at an intermediate holding company and a mix of funds from the BBI level. Also, BBI would assume roughly $740 million of existing NorthWestern debt. NorthWestern's credit measures, which now adequately support the 'BB+' rating, would weaken after the transaction closes due to the incremental debt, which could put downward rating pressure on the company. — Gerrit Jepsen

NRG Energy Inc. (B+/Stable/B-2)

In 2005, NRG Energy Inc. performed as expected, with funds from operations (FFO) to interest coverage at 3.4x and FFO to total debt at 17%. NRG's credit quality should not significantly deteriorate in the short term, because they will continue to benefit from the hedges the company has in place at Texas Genco. For the longer term, NRG remains exposed to the high business risk of operating as predominantly a merchant generator where cash flows may be volatile, which will limit upgrade potential. In addition, management's appetite for growth could either limit upward rating potential or may even place downward pressure on ratings. — David Bodek

NSTAR (A+/Stable/A-1)

Standard & Poor's Ratings Services expects that NSTAR will continue to pursue low-operating transmission and distribution activities while preserving its strong financial profile. Although financial performance may weaken in 2006, due to the deferral of transition costs, it should remain strong for the rating. Standard & Poor's expects adjusted funds from operations (FFO) interest coverage to average more than 5x while adjusted FFO to total debt to average about 25%. Debt leverage should gradually improve to marginally to about 59% mainly as a result of higher retained earnings and minimal debt maturities. — Jeffrey Wolinsky

NSTAR Gas Co. (A+/Stable/--)

See NSTAR — Jeffrey Wolinsky

OGE Energy Corp. (BBB+/Stable/A-2)

In the short term, Standard & Poor's Ratings Services expects cash flow metrics for OGE Energy Corp. to remain fairly stable at the consolidated level. Lower than anticipated utility rate approval in Oklahoma is balanced by stronger gathering and processing operations at Enogex Inc. Upside potential derives from a wind project at Oklahoma Gas & Electric Co., which could start as early as 2007, and from two potential projects by Enogex. Some funding will come from the recent sale of its gas gathering assets in Oklahoma. The company also plans a rate case filing in Arkansas in July 2006. — Jeanny Silva

Ohio Edison Co. (BBB/Stable/--)

See FirstEnergy Corp. — Aneesh Prabhu

Ohio Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Oklahoma Gas & Electric Co. (BBB+/Stable/A-2)

See OGE Energy Corp. — Jeanny Silva

ONEOK Inc. (BBB/Stable/A-2)

Standard & Poor's Ratings Services recently affirmed its corporate credit rating on ONEOK Inc. and removed it from CreditWatch. The rating affirmation incorporated Standard & Poor's assessment of ONEOK's transfer of its midstream assets to ONEOK Partners LP, as well as ONEOK's use of a portion of its proceeds from the asset transfer to repay short-term debt. Standard & Poor's expects ONEOK Partners to serve as ONEOK's primary growth vehicle and, given ONEOK's 100% general partnership interest in ONEOK Partners, we view the ratings on the two entities as increasingly intertwined. — Plana Lee

Orange and Rockland Utilities Inc. (A/Negative/A-1)

See Consolidated Edison Inc. — Jeffrey Wolinsky

Orion Power Holdings (B/Negative/--)

See Reliant Energy Inc. — Dimitri Nikas

Otter Tail Corp. (BBB+/Stable/--)

Otter Tail Corp.'s electric utility, which internally funds its financing needs, continues to work toward the construction of a second coal unit at Big Stone that will likely result in the company's accessing the external markets for debt and equity financing. Due to a relatively high dividend payout ratio and the capital-spending needs of the competitive businesses, liquidity is likely to continue to be constrained, but there have been recent improvements. Although not at the upper end of the ranges, cash flow measures and debt leverage are within their respective benchmark ranges for the 'BBB' rating. — Gerrit Jepsen

Pacific Gas & Electric Co. (BBB/Stable/--)

Long-term electricity- and fuel-procurement activities are ongoing and will define the utility's operational and financial profile. Financial performance remains exposed to volatile fuel- and power-procurement costs and the California Public Utilities Commission's response to material changes in utility costs. Also, expiration of California Department of Water Resources and qualifying facility contracts in coming years will heighten financial exposure related to power procurement. The February 2005 rating upgrade and the 2006's improvement in the business profile score reflect the interplay between sound financial performance and actions by the regulator that are protective of bondholder interests. A focus on regulated businesses is viewed as supportive of credit quality. — David Bodek

PacifiCorp (A-/Stable/A-2)

Scottish Power PLC's sale of PacifiCorp to MidAmerican Energy Holdings Inc. (MEHC) was completed in March 2006. The focus will now turn to integrating PacifiCorp's six state operations into MEHC, and a reorganization of the utility has begun. PacifiCorp has initiated large rate cases in Oregon and Utah, its two most important markets, as well as in Washington. Improved ROE and a settlement on cost allocation issues among the various states, are expected to be the focus of new management. — Swami Venkataraman

PanEnergy Corp. (BBB/Positive/--)

See Duke Energy Corp. — Dimitri Nikas

Panhandle Eastern Pipe Line LLC (BBB/Negative/--)

See Southern Union Co. — Plana Lee

PECO Energy Co. (BBB+/Watch Neg/A-2)

See Exelon Corp. — Richard Cortright

Pennsylvania Electric Co. (BBB/Stable/--)

See FirstEnergy Corp. — Aneesh Prabhu

Pennsylvania Power Co. (BBB/Stable/--)

See FirstEnergy Corp. — Aneesh Prabhu

Peoples Energy Corp. (A-/Negative/A-2)

The settlement with the Illinois Commerce Commission in March 2006 for $100 million of reimbursement back to customers (plus other charges up to $20 million in 2006) based on gas purchase prudence reviews for 2000-2004 period is exptected to be funded by short-term debt initially, then through additional equity issuance or funds from asset sales. Ratings may be under pressure if the balance sheet is not improved back to its levels before the charges by the end of the fiscal year. Rate cases are expected to be filed for both utilities in the summer of 2006, but the cash effect of any possible rate increase will not occur until late spring 2007. Financial ratios are expected to be lower than benchmark levels for the near term. Unregulated businesses contribute positive cash flow, but have a higher business risk profile. In 2006, the composition of unregulated investments changed with the company exiting the power generation sector and reinvesting the proceeds from power generation asset sales into the oil and gas sector. Prudent risk management practices are expected to continue with the newly acquired oil and gas assets ($139 million investment). — Elif Acar

Peoples Gas Light & Coke Co. (The) (A-/Negative/A-2)

See Peoples Energy Corp. — Elif Acar

PEPCO Holdings Inc. (BBB+/Watch Neg/A-2)

The CreditWatch listing reflects the effect of recent regulatory decisions for utility subsidiaries Delmarva Power & Light Co. and Potomac Electric Power Co. (Pepco) on PHI's credit quality and financial measures, which have been weak for the 'BBB+' rating. Although there is greater clarity about the regulatory actions and other issues, uncertainty remains about the effect on PHI's financial measures over the intermediate term. After reviewing the effect on the financial measures, the CreditWatch listing will be resolved. — Gerrit Jepsen

Piedmont Natural Gas Co. Inc. (A/Stable/--)

The ratings and stable outlook on Piedmont Natural Gas Co. Inc. reflect the successful completion of the integration of its North Carolina Natural Gas Corp. acquisition, continued healthy economic growth in the company's service areas, and responsive regulation in its jurisdictions. Importantly, Piedmont's attentiveness to credit quality, supported by prudent growth management, sound credit protection measures, moderate use of debt leverage, and effective liability and liquidity management, promote rating stability at the current level. — Brian Janiak

Pinnacle West Capital Corp. (BBB-/Stable/A-3)

Consolidated cash flows remain weak and are expected to weaken through the third quarter, principally because of regulatory lag associated with Arizona Public Service's growing deferred power costs, which totaled $169 million as of March 31, 2006. In conjunction with the utilty's peak summer season, these deferrals are expected to grow rapidly in the coming months. At the same time, uncertainty remains over whether Palo Verde 1 will return to serve on time and achieve improved performance. Both factors are expected to pressure the rating and outlook, despite a May 1 seven mil. per kilowatt-hour surcharge approved by the Arizona Corporation Commission that should limit the growth in deferrals to a balance of around $170 million. Summer will be critical for the company. A new rate case is scheduled to have hearings in the fall of 2006, but it is unclear when a decision will be issued. — Anne Selting

Pivotal Utility Holdings (A-/Negative/--)

See AGL Resources Inc. — Ravi Myneni

PNM Resources Inc. (BBB/Negative/A-3)

PNM Resources Inc.'s financial risk profile will continue to depend on management's ability to lower operating costs to offset the rate reduction that is part of the five-year rate settlement. Credit quality of the consolidated company will depend on PNM Resources' ability to manage the retail business in New Mexico, the competitive retail business in Texas, and the wholesale business in the Western electric markets. — Chinelo Chidozie

Portland General Electric Co. (BBB+/Negative/A-2)

Portland General Electric Co.'s (PGE) continuing troubles at the 585 MW Boardman coal plant have begun to cause a slight weakening in the company's financial measures, with funds from operations to average total debt falling to a still acceptable 19% for the 12 months ending March 31, 2006, versus 22% for the similar period ending Dec. 31, 2005. The plant experienced another forced outage on June 13, 2006, the third since October 2005. The company expects that the plant will be offline until early July, and that replacement power costs will range between $1 million and $4 million. The company has already incurred in the first and second quarters of 2006 about $48 million in replacement power costs related to the October 2005 and February 2006 plant outages. PGE filed a general rate case in March 2006, as well as an application with the Oregon Public Utilities Commission, seeking deferral of replacement power costs through Feb. 5, 2006, when Boardman returned to service after the first plant outage. — Leo Carrillo

Potomac Capital Investment Corp. (BBB/Watch Neg/--)

See PEPCO Holdings Inc. — Gerrit Jepsen

Potomac Edison Co. (BB+/Positive/--)

See Allegheny Energy Inc. — Aneesh Prabhu

Potomac Electric Power Co. (BBB+/Watch Neg/A-2)

See PEPCO Holdings Inc.	Gerrit Jepsen
PPL Corp. (BBB/Stable/--) In 2006, PPL Corp.'s merchant assets benefit from higher energy prices in PJM and the Pacific Northwest. Margins also benefit from a price escalator in its generation rate cap with PPL Electric Utilities. Still, the company needs current levels of prices to fund its projected capital-spending needs on pollution control equipment. To ensure sufficient cash flow, the company has hedged output and coal requirements for 2006. Liquidity remains adequate with about $2 billion availability under PPL Energy's credit lines. While PPL's debt leverage remains high at about 58%, funds from operations to interest coverage has stabilized and remains adequate at about 4x.	Aneesh Prabhu
PPL Energy Supply LLC (BBB/Stable/--) See PPL Corp.	Aneesh Prabhu
PPL Electric Utilities Corp. (A-/Stable/A-2) The higher credit rating for PPL Electric Utilities Corp. reflects its insulation from its weaker parent, PPL Corp., and its improving financial profile which has benefited from a $194 million rate increase in 2005, providing also for the recovery of all PJM-related transmission costs.	Aneesh Prabhu
Progress Energy Inc. (BBB/Stable/A-2) Financial performance for the 12-months ending March 30, 2006 improved slightly as the fuel surcharge at the utilities continue. The short-term focus is the regulatory approval of the $276 million fuel underrecovery in North Carolina and the execution of the debt reduction.	Jodi Hecht
PSEG Energy Holdings LLC (BB-/Negative/--) The ratings on PSEG Energy Holdings LLC reflect the company's stand-alone creditworthiness and does not reflect the benefits of affiliation with financially stronger companies. Standard & Poor's Ratings Services believes that Public Service Enterprise Group Inc. will not deploy cash generated at Public Service Electric & Gas Co. and PSEG Power LLC to infuse capital into PSEG Energy Holdings, which has experienced several failed investments. Preservation of credit quality hinges on several factors. The outcome of an IRS investigation into tax deductions related to the company's lease portfolio represents a sizable contingent exposure. Tax deductions flowing from leasing transactions are an important component of the company's cash flow. Other important credit drivers include Exelon Corp.'s future plans for the liquidation of this company and the extent to which cash flows are affected by asset dispositions pending the final liquidation.	David Bodek
PSEG Power LLC (BBB/Watch Dev/--) PSEG Power LLC's nuclear units are now operated by contract Exelon employees. Future credit quality will depend on the sustainability of the recent improvements, as well as the ability to reduce leverage. The Exelon merger has the potential to rehabilitate PSEG Power's nuclear units and introduce cost savings.	David Bodek
PSI Energy Inc. (BBB/Positive/A-2) See Duke Energy Corp.	Dimitri Nikas
Public Service Co. of Colorado (BBB/Stable/A-2) See Xcel Energy Inc.	David Bodek
Public Service Co. of New Hampshire (BBB/Stable/--) See Northeast Utilities	Arleen Spangler
Public Service Co. of New Mexico (BBB/Negative/A-3) See PNM Resources Inc.	Chinelo Chidozie
Public Service Co. of North Carolina Inc. (A-/Stable/A-2) See SCANA Corp.	Brian Janiak
Public Service Co. of Oklahoma (BBB/Stable/--) See American Electric Power Co. Inc.	Todd Shipman
Public Service Electric & Gas Co. (BBB/Watch Dev/--) This regulated utility continues to benefit from pass-through mechanisms that insulate it from commodity price and demand volatility. However, by virtue of its affiliation with Public Service Enterprise Group's unregulated businesses, the utility's credit quality is exposed to several significant uncertainties, including the performance of PSEG Power's nuclear units and their ability to discharge PSEG Power's contractual provider of last resort obligations. Also see Public Service	David Bodek

Enterprise Group Inc.

Public Service Enterprise Group Inc. (BBB/Watch Dev/--)

Public Service Enterprise Group Inc. (PSEG), a holding company, is exposed to volatile energy markets and operational issues. The CreditWatch developing listing reflects the divergent credit paths facing the Enterprise companies. If the announced merger with Exelon Corp. is consummated, as anticipated in mid-2006, the credit quality of Enterprise and its subsidiaries may benefit from predicted synergies and from the company's integration into a larger entity with a stronger credit profile. However, if the merger does not come to pass, credit quality may suffer because of high leverage, as well as operational issues. Exelon, as the operator of the largest nuclear fleet in the U.S., is viewed as having the ability to rehabilitate the reliability of PSEG's nuclear program. — David Bodek

Puget Energy Inc. (BBB-/Stable/--)

Regulatory support will be a decisive factor in driving possible rating improvement, as the company implements its $1.4 billion, two-year capital program for 2006 and 2007, which includes construction on the 220 MW Wild Horse wind project by Dec. 2006. In its Feb. 17, 2006 filing, Puget Sound Energy (PSE) requested additional rate relief, a higher allowed ROE and equity ratio, approval of a major power-purchase contract, and several major capital additions, and several major improvements to PSE's rate structure, including modification to its power cost adjustment mechanism and the addition of a gas "decoupling" mechanism and depreciation tracker. In May 2006, the company sold its last remaining unregulated subsidiary, InfrastruX, a utility infrastructure construction services firm for $275 million. — Leo Carrillo

Puget Sound Energy Inc. (BBB-/Stable/A-3)

See Puget Sound Energy Inc. — Leo Carrillo

Questar Corp. (--/--/A-2)

Operating performance and credit measures improved significantly in the first quarter due to higher natural gas production and realized gas prices from Questar Market Resources. Financial performance is expected remain satisfactory for the rest of 2006, as the company has hedged a substantial portion of its anticipated natural gas production for 2006. Credit measures are solid for the rating reflecting the benefits of a favorable conditions in its natural gas business. The other business units, Questar Pipeline Co. and Questar Gas Co. continue to perform well and within expectations. — Brian Janiak

Questar Gas Co. (A-/Stable/--)

See Questar Corp. — Brian Janiak

Questar Market Resources Inc. (BBB+/Stable/--)

See Questar Corp. — Brian Janiak

Questar Pipeline Co. (A-/Stable/--)

See Questar Corp. — Brian Janiak

Reliant Energy Inc. (B/Negative/--)

Standard & Poor's Ratings Services expects Reliant Energy Inc. to experience a financially weak 2006, mainly as a result of losses related to hedges in the wholesale business and the unfavorable price to beat arrangement in the retail business. While the company has terminated many of its wholesale hedges, these will take a few years to roll off. In addition, there is uncertainty as to how the retail market will develop starting in 2007, once the price to beat arrangement ends. While credit measures could begin to improve in 2007, Standard & Poor's is concerned that there could be a financial covenant breach in 2006, if the company's financial performance deviates from its plan. — Dimitri Nikas

Rochester Gas & Electric Corp. (BBB+/Stable/A-2)

See Energy East Corp. — Jeffrey Wolinsky

Rockland Electric Co. (A/Negative/A-1)

See Consolidated Edison Inc. — Jeffrey Wolinsky

San Diego Gas & Electric Co. (A/Stable/A-1)

San Diego Gas & Electric Co. is entering a period of significant rate base growth in generation and transmission and is also in the process of contracting for substantial renewable assets. — Swami Venkataraman

Savannah Electric & Power Co. (A/Stable/--)

See Southern Co. — Terry Pratt

SCANA Corp. (A-/Stable/--)

South Carolina Electric & Gas Co., SCANA Corp.'s largest subsidiary, generates most of the consolidated company's net — Brian Janiak income and cash flow (90% and 80%, respectively). Stable cash flow from regulated electric and gas businesses, constructive regulatory environments, and competitive business positions support credit quality. Management's commitment to credit quality and its ability to further reduce debt through the use of expected free cash flow in 2006, as well as favorable rate relief for its significant capital expenditure projects, should allow the company to further strengthen its financial risk profile in the near term.

SEMCO Energy Inc. (BB-/Stable/--)

Recent refinancings are expected to help reduce the company's interest expense and should improve some coverage metrics. However, SEMCO Energy Inc. will remain challenged in its ability to reduce its high level of debt. The company's strong storage position relieved pressure on its liquidity needs during this heating season. — Brian Janiak

Sempra Energy (BBB+/Stable/A-2)

Consistent and predictable financial performance is expected at Sempra Energy utilities and Sempra Generation. Significant, upcoming capital expenditures at the utilities, liquid natural gas (LNG) projects, Rockies Express pipeline, and perhaps additional nonregulated assets, could limit the amount of debt that can be paid down. Under conservative assumptions for Sempra Commodities, financial ratios maybe be somewhat weak in 2006 and 2007, when LNG investments are consolidated. Ratios are expected to be strong from 2008 onward, even under conservative assumptions. — Swami Venkataraman

Sierra Pacific Power Co. (B+/Positive/--)

See Sierra Pacific Resources — Swami Venkataraman

Sierra Pacific Resources (B+/Positive/--)

Sierra Pacific Resources' consolidated financial ratios are expected to show modest improvement as the company collects deferred costs and incurs no additional disallowances. Regulatory and liquidity risks have declined substantially over the past few years. Prospects for an upgrade will be strengthened by an equity issuance to support the large capital-expenditure plans at the utilities. — Swami Venkataraman

South Carolina Electric & Gas Co. (A-/Stable/A-2)

See SCANA Corp. — Brian Janiak

South Jersey Gas Co. (BBB+/Stable/--)

On June 19, 2006, Standard & Poor's Ratings Services affirmed its ratings on South Jersey Gas Co. and revised the the outlook to stable from negative. The revision reflects improved financial metrics that are solidly in line with expectations for the 'BBB+' rating for the 12 months ended March 31, 2006, including adjusted funds from operations (FFO) to total debt of about 14.5%, adjusted FFO interest coverage of 4x, and adjusted average total debt to capital of 52%. Continued ratings stability relies on a moderate proportion of capital spending on unregulated pursuits, prudent financing of growth strategies, and a greater portion of cash flow at parent South Jersey Industries from the regulated gas utility. — Plana Lee

Southern California Edison Co. (BBB+/Stable/A-2)

Long-term electricity and fuel procurement activities are ongoing and will define the utility's operational and financial profile. Financial performance remains exposed to volatile fuel and power-procurement costs and the California Public Utilities Commision's (CPUC) response to material changes in utility costs. Also, expiration of California Department of Water Resources and qualifying facility contracts in coming years will heighten financial exposure related to power procurement. In a recent positive development, the CPUC provided the utility with a nearly $1 billion revenue increase to realign revenues and expenses, which action represents the CPUC's reaffirmation of its commitment to sound credit quality. See also Edison International. — David Bodek

Southern California Gas Co. (A/Stable/A-1)

The ratings on Southern California Gas Co. reflect the consolidated profile of Sempra Energy. Regulation in California, which, among other things, mandates that the utilities maintain a 48% equity layer, provides sufficient insulation to separate the corporate credit ratings of the utilities from those of the parent and nonregulated subsidiaries. — Swami Venkataraman

Southern Co. (A/Stable/A-1)

The Georgia Public Service Commission's June 2006 approval of an approximate 7% increase in rates for Georgia Power Co. will help reduce the large unrecovered fuel balance, which was $784 million at the end of March 2006. The Florida Public Service Comission's June 2006 approval of Gulf Power Co.'s proposed settlement with user groups will enable the utility to recover hurricane repair costs through a surcharge until mid-2009. Mississippi Power Co. continues to examine ways to fund storm repairs costs, including securitization, but may benefit from large federal grants in 2006. Financial performance remains sound and stable; adjusted funds from operations to interest coverage was 5.3x for the year-ended March 31, 2006 and should be around 5x through 2008. — Terry Pratt

Southern Connecticut Gas Co. (BBB+/Stable/A-2)

See Energy East Corp. — Jeffrey Wolinsky

Southern Electric Generating Co. (A/Stable/A-1)

See Southern Co. Terry Pratt

Southern Indiana Gas & Electric Co. (A-/Stable/--)

See Vectren Corp. Elif Acar

Southern Natural Gas Co. (B+/Positive/B-3)

See El Paso Corp. Ben Tsocanos

Southern Power Co. (BBB+/Stable/A-2)

The corporate credit rating and outlook are unchanged as a result of the Rowan and DeSoto plant acquisitions, new EnergyUnited full requirements agreement, new purchased-power agreements that will be supplied by the new plant, and participation in the Integrated Gasification combined-cycle unit in Florida, but these developments reflect an increase in business risk. The recent affiliate abuse settlement with parent Southern Co., Calpine Corp., and Coral Energy Holding L.P. is favorable, because it secures Southern Power Co.'s continued participation in the Southern pool. For the 12 months ended March 31, 2006, funds from operations to interest coverage was about 3.5x and adjusted total debt to total capital was about 58%. Terry Pratt

Southern Star Central Corp. (BBB-/Stable/--)

See Southern Star Central Gas Pipeline Inc. Plana Lee

Southern Star Central Gas Pipeline Inc. (BBB-/Stable/--)

The company continues to benefit from better profitability due to its $18 million (or 12%) rate increase. Ratings stability relies on moderate and prudently financed expansions. Capital expenditures in 2006 are expected to be moderate at about $41 million, including the Ozark Trails expansion. Plana Lee

Southern Union Co. (BBB/Negative/--)

On March 1, 2006, Southern Union Co. acquired 100% of the partnership interests of Sid Richardson Energy Services' gas gathering and processing assets in Texas for $1.6 billion. The acquisition was funded through a bridge loan facility in the amount of $1.6 billion. Cash proceeds from the sale of Southern Union's gas distribution businesses in Pennsylvania and Rhode Island, as well as a mix of debt and equity, is expected to improve the company's financial metrics to levels more commensurate with the 'BBB' rating. The outlook remains negative, pending execution of the company's financing plan. Plana Lee

Southwest Gas Corp. (BBB-/Stable/--)

Southwest Gas Corp. posted good operating measures in the first quarter, due to realizing the benefits of recent favorable rate decisions and a growing rate base. The Arizona Corporation Commission increased rates in Arizona by $49.3 million annually effective March 1, 2006, which helps the company but fell well short of management's rate request. Credit measures remain solid for the rating. Still, management is likely to be challenged by the capital needs of its relatively fast-growing service territories. Leo Carrillo

Southwestern Electric Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. Todd Shipman

Southwestern Public Service Co. (BBB/Stable/A-2)

See Xcel Energy Inc. David Bodek

System Energy Resources Inc. (BBB-/Watch Neg/--)

See Entergy Corp. Dimitri Nikas

Tampa Electric Co. (BBB-/Stable/A-3)

Tampa Electric Co.'s cash flow should benefit from deferred fuel cost recovery, partially funding elevated capital spending for environmental compliance and incremental peaking capacity. The utility's ratings are supported by strong customer growth, minimal reliance on industrial load, a strong regulated local gas distribution unit, and a supportive regulatory environment. Jodi Hecht

TECO Energy Inc. (BB/Stable/B-1)

TECO Energy Inc. has completed the sale of substanially all its merchant power assets and is refocusing on its core regulated business. Its utility, Tampa Electric Co., is concentrating on meeting the strong demand growth of its market. The company intends to build cash and refinance opportunistically ahead of sizable 2007 maturities. Standard & Poor's Ratings Services anticipates that cash flow from synthetic fuel operations, which comprises a substantial component of consolidated cash flow, will likely be reduced by the effect of high oil prices, reducing the expected pace of debt' reduction. Debt incurred to pursue a merchant strategy continues to act as a drag on financial measures and credit quality. Jodi Hecht

Tennessee Gas Pipeline Co. (B+/Positive/B-3) See El Paso Corp.	Ben Tsocanos
Texas Eastern Transmission LP (BBB/Positive/--) See Duke Energy Corp.	Dimitri Nikas
Texas-New Mexico Power Co. (BBB/Negative/--) See PNM Resources Inc,	Chinelo Chidozie
Thermal North America Inc. (BB-/Stable/--) Financial performance for the first quarter was somewhat negatively affected by unusually warm weather, especially in the Northeast U.S., but performance should trend upwards with more favorable weather in the second quarter. The company continues to plan for improved regulatory treatment at St. Louis and Kansas City, and continues with capital improvements at Grey's Ferry.	Terry Pratt
Toledo Edison Co. (BBB/Stable/--) See FirstEnergy Corp.	Aneesh Prabhu
Transcontinental Gas Pipe Line Corp. (BB-/Positive/--) See Williams Cos.	Jeffrey Wolinsky
Transwestern Holding Co. LLC (BBB/Stable/--) See CrossCountry Energy LLC	Plana Lee
Transwestern Pipeline Co. LLC (BBB/Stable/--) See CrossCountry Energy LLC	Plana Lee
Tucson Electric Power Co. (BB/Stable/B-1) Strong cash flows are an important credit attribute of this very leveraged company, with parent UniSource expecting to fund rising capital expenditures internally and slowly work toward paying down Tucson Electric Power Co. (TEP) debt and capital lease balances. Due to a rate cap in place through December 2008, TEP remains vulnerable to unplanned outages at its coal plants. The Arizona Corporation Commission has initiated a proceeding to determine how TEP's rates will be set after the rate cap expires in 2008. Hearings are scheduled for January 2007.	Anne Selting
TXU Corp. (BBB-/Negative/--) The negative outlook reflects the potential for TXU Corp.'s creditworthiness to be negatively affected by its $11 billion investment plan to construct 11 coal plants totaling about 8,000 MW in Texas by 2010. Sufficient details are not yet available to determine if the credit effects of the investment, which TXU will develop on a legally nonrecourse basis, will negatively affect the ratings of TXU or its subsidiaries, TXU Energy Co. LLC and TXU Electric Delivery Co., if we place a portion of the nonrecourse debt onto the consolidated TXU rating to reflect potential support to this large investment.	Terry Pratt
TXU Electric Delivery Co. (BBB-/Negative/--) See TXU Corp.	Terry Pratt
TXU Energy Co. LLC (BBB-/Negative/--) See TXU Corp.	Terry Pratt
Union Light Heat & Power Co. (BBB/Positive/--) See Duke Energy Corp.	Dimitri Nikas
Union Electric Co. (BBB+/Watch Neg/A-2) See Ameren Corp.	Barbara Eiseman
United Water New Jersey (A-/Watch Pos/--) United Water New Jersey's ratings are tied to those of parent Suez. The ratings on United Waterworks and United Water New Jersey remain on CreditWatch with positive implications, reflecting the improvement in Suez S.A.'s business and financial risk profiles that would result from its announced merger with lower-risk Gaz de France S.A. However, if the combined entity is spun off from the United Water assets, United Water New Jersey and United Waterworks' stand-alone credit quality could be in the 'BBB' rating category, particularly if intermediate parent United Water Inc. retains its riskier	Plana Lee

contract management segment.

United Waterworks (A-/Watch Pos/--)

See United Water New Jersey — Plana Lee

Vectren Corp. (A-/Stable/--)

Indiana utilities are experiencing positive effects from the newly granted NTA mechanism awarded by regulators. Warmer than normal weather had a much-reduced negative affect on margins. Revenues have increased for all three utilities based on rate increases achieved during 2005. Unregulated acitivities continue to provide positive income at an arm's length and mostly support regulated operations. The negative outcome of the jury trial between ProLiance (50% controlled subsidiary of Vectren Corp.) and the City of Huntsville, Ala. against ProLiance is not expected to affect the credit rating of Vectren Corp., but earnings from this sector will be volatile in the next couple of years. Also, synfuel-related earnings are at stake due to high oil prices affecting these credits. Without the synfuel credit, Vectren has to absorb the losses from Pace Carbon subsidiary. Financial ratios may be negatively affected from such outcomes. High debt leverage weakens the financial risk profile. — Elif Acar

Vectren Utility Holdings Inc. (A-/Stable/A-2)

See Vectren Corp. — Elif Acar

Virginia Electric & Power Co. (BBB/Stable/A-2)

See Dominion Resources Inc — Aneesh Prabhu

Washington Gas Light Co. (AA-/Negative/A-1)

See WGL Holdings Inc. — Ravi Myneni

West Penn Power Co. (BB+/Positive/--)

See Allegheny Energy Inc. — Aneesh Prabhu

Westar Energy Inc. (BB+/Positive/--)

The Kansas Corporation Commission's (KCC) February 2006 order on reconsideration did not result in additional meaningful rate relief. The authorized rate increase of only $3 million, compared with the $84 million requested, was insufficient to raise the company's ratings as soon as was expected. However, the KCC's adoption of certain important rate-making mechanisms, including a fuel adjustment clause and an environmental cost recovery rider, coupled with continued credit supportive actions by management, should still lead to higher ratings, despite restrictive regulation in Kansas. Regardless of the marginal rate relief recently granted, the company intends to pursue its stated goal of achieving a 60% to 75% payout ratio. Financial improvement will depend on kilowatt-hour sales growth, operation of the various tracker mechanisms, and effective management of operations and maintenance expenses. — Barbara Eiseman

Western Massachusetts Electric Co. (BBB/Stable/--)

See Northeast Utilities — Arleen Spangler

WGL Holdings Inc. (AA-/Negative/A-1)

Conservation during the previous winter season led to a decline in financial metrics, as only the Maryland jurisdiction benefited from revenue normalization at Washington Gas Light Co. Local opposition to the proposed construction of a liquified natural gas peaking plant in Chillum, Maryland has introduced greater uncertainty for this project. Trailing 12-month adjusted funds from operations (FFO) to interest coverage is 4.5x and adjusted FFO to average total debt is 22.1%. — Ravi Myneni

Williams Cos. Inc. (The) (BB-/Positive/--)

Standard & Poor's Ratings Services expects The Williams Cos. Inc.'s financial ratios will improve as a result of the additional cash from the exploration and production segment. We forecast funds from operations (FFO) to debt and FFO to interest to improve to 17% and 2.8x in 2006, which is probably insufficient to warrant an upgrade this year. However, if cash spending at its power segment is considerably higher than expectations or financial ratios fall considerably below expectations, the outlook could be revised to stable. The recent expansion of the master limited partnership somewhat detracts from credit. Conversely, the recent shareholder lawsuit settlement favors credit. — Jeffrey Wolinsky

Wisconsin Electric Power Co. (A-/Negative/A-2)

See Wisconsin Energy Corp. — Gerrit Jepsen

Wisconsin Energy Corp. (BBB+/Negative/A-2)

Standard & Poor's Ratings Services expects Wisconsin Energy Corp.'s financial measures to be be mixed for the rating during its heavy construction program, and improvement in cash flow protection measures expected in future years will depend highly on supportive rate treatment and a well-executed capital-spending program through 2011, which is well — Gerrit Jepsen above average historical levels. Although it expects increasing cash flow from operations over the next several years, Wisconsin Energy will have negative free operating cash flow after capital spending and before dividends. The company plans to fund with debt the portion of its cash requirements that exceeds cash flow, thereby requiring new borrowings that must be prudent for the company to maintain its credit profile.

Wisconsin Gas LLC (A-/Negative/A-2)

See Wisconsin Energy Corp. — Gerrit Jepsen

Wisconsin Power & Light Co. (A-/Stable/A-2)

See Alliant Energy Corp — Jeanny Silva

Wisconsin Public Service Corp. (A+/Negative/A-1)

See WPS Resources Corp. — Gerrit Jepsen

WPS Resources Corp. (A/Negative/A-1)

In the intermediate term, WPS Resources Corp. has multiple events that must be successfully completed before its performance can be considered stable. The gas utilities being acquired in Michigan and Minnesota from Aquila Inc. should successfully be integrated into the existing corporate family, and meet Standard & Poor's Ratings Services' expectations for contributions to consolidated funds from operations. In addition, we are continuing to monitor the company's current construction program for being within budget; the improvement of available liquidity; and the strengthening and stabilization of its financial position. — Gerrit Jepsen

Xcel Energy Inc. (BBB/Stable/A-2)

Xcel Energy Inc.'s subsidiaries continue to lower overall costs by centralizing and streamlining joint operating activities. A settlement related to the Least Cost Plan in Colorado supports Public Service Colorado's credit by recognizing that equity should be at least 56% of capital to offset purchased-power obligations and that future plant construction costs should be included in rate base on a current basis. Subsequent electric rate cases have been filed in Minnesota, Wisconsin, and North Dakota; gas rate cases have been filed in Colorado and Wisconsin. These rate increases and continued regulatory support of the utilities' credit profiles are important factors in maintaining the current credit rating. — David Bodek

Yankee Gas Services Co. (BBB/Stable/--)

See Northeast Utilities — Arleen Spangler

York Water Co. (The) (A-/Stable/--)

York Water Co. continues to expand its reach through robust, regionally focused acquisition activity, which is expected to continue. Upward rating potential in the near term is unlikely, given the company's lack of free cash flow and substantial capital expenditures expected in 2006. — Plana Lee

Ratings are as of June 22, 2006.

Quarterly Rating Activity

Table 2

Recent Rating/Outlook/CreditWatch Actions*

Issuer	To	From	Date	Reason
ANR Pipeline Co.	B+/Positive/--	B/Positive/--	May 30, 2006	See El Paso Corp.
Baltimore Gas & Electric Co.	BBB+/Watch Dev/A-2	BBB+/Watch Pos/A-2	April 7, 2006	See Constellation Energy Group Inc.
Black Hills Corp.	BBB-/Negative/--	BBB-/Watch Neg/--	May 1, 2006	The rating action reflects Black Hills' withdrawal of its offer to acquire NorthWestern Corp., which ultimately accepted an offer from Babcock & Brown Infrastructure.
Black Hills Power Inc.	BBB-/Negative/--	BBB-/Watch Neg/--	May 1, 2006	See Black Hills Corp.
Boston Edison Co.	A+/Stable/A-1	A/Positive/A-1	May 17, 2006	See NSTAR
Cambridge Electric Light Co.	A+/Stable/A-1	A/Positive/A-1	May 17, 2006	See NSTAR
Central Vermont	B+/Stable/--	BBB-/Watch Neg/--	June	The company requested a rate increase of about 6.15% this past

Public Service Corp.			10, 2005	May, which is a critical part of its strategy to improve ratings. In addition, an appeal of its 2005 rate case decision is pending and a decision could be forthcoming. Moreover, management has implemented various cost savings initiatives to improve its financial performance. Furthermore, the company has reorganized its board of directors to be composed of more individuals from its service territory which may help in its efforts to mend its regulatory relationships.
Cincinnati Gas & Electric Co.	BBB/Positive/--	BBB/Stable/--	May 25, 2006	See Duke Energy Corp.
Cinergy Corp.	BBB/Positive/A-2	BBB/Stable/A-2	May 25, 2006	See Duke Energy Corp.
Coastal Natural Gas Co.	B+/Positive/--	B/Positive/--	May 30, 2006	See El Paso Corp.
Colorado Interstate Gas Co.	B+/Positive/--	B/Positive/--	May 30, 2006	See El Paso Corp.
Commonwealth Electric Co.	A+/Stable/--	A/Positive/--	May 17, 2006	See NSTAR
Constellation Energy Group Inc.	BBB+/Watch Dev/A-2	BBB+/Watch Pos/A-2	April 7, 2006	The rating action follows regulatory and legislative developments in Maryland that have the potential to negatively affect Constellation's consolidated credit quality. At the same time, the potential for a ratings upgrade assumes the announced merger with higher rated FPL Group Inc. (A/Watch Neg/--) is consummated and also assumes that the combined company will not pursue a more aggressive business strategy or financial policy than each company had pursued individually before the merger.
Consolidated Edison Inc.	A/Negative/A-2	A/Stable/A-1	June 6, 2006	The negative outlook on Consolidated Edison Inc. reflects the expectation that financial ratios will deteriorate significantly in 2006, with funds from operations (FFO) to debt dropping to about 10% and FFO interest coverage dropping to 2.7x. We expect the ratios to somewhat improve in 2007, as the existing Consolidated Edison Co. of New York (CECONY) rate increase becomes effective. A significantly greater-than-forecast deterioration in the company's financial ratios could lead to a downgrade. Implicit in the current rating is the expectation that the 2008 CECONY rate increase will be sufficient to improve FFO to debt to about 16% and FFO interest above 3.5x. If the rate increase is not sufficient, the rating could be lowered. We do not expect the company to undertake any major acquisitions.
Consolidated Edison Co. of New York Inc.	A/Negative/A-2	A/Stable/A-1	June 6, 2006	See Consolidated Edison Inc.
Duke Capital LLC	BBB/Positive/A-2	BBB/Stable/--	May 25, 2006	See Duke Energy Corp.
Duke Energy Corp.	BBB/Positive/--	BBB/Stable/--	May 25, 2006	The positive outlook on Duke Energy reflects the potential for improved credit quality and subsequently higher ratings, if the company can successfully sell Cinergy Corp.' s commercial trading and marketing operations, and also successfully complete the merger integration process with Cinergy, achieving the expected cost savings. If either of these events fail to occur, Standard & Poor's will consider revising the outlook to stable. In the absence of a severely adverse credit event, an outlook revision to negative is not presently expected.
Duke Power Company LLC	BBB/Positive/A-2	BBB/Stable/A-2	May 25, 2006	See Duke Energy Corp.
El Paso CGP Co.	B+/Positive/B-3	B/Positive/B-3	May 30, 2006	See El Paso Corp.
El Paso Corp.	B+/Positive/B-3	B/Positive/B-3	May 30, 2006	The upgrades recognize the considerable progress that the company has made refocusing on the core pipeline and oil and gas exploration and production operations and stabilizing its financial position. The company's ventures into diverse unregulated business, which entailed significant financial leveraging and market risk, now represent a minimal component of El Paso's profile. The upgrade also incorporates our assessment that El Paso has firmed up its once precarious liquidity position ahead of still sizable, near-term maturities, although refinancing risk remains.

El Paso Energy Credit Corp.	BB-/Positive/--	B+/Positive/--	May 30, 2006	See El Paso Corp.
El Paso Natural Gas Co.	B+/Positive/--	B/Positive/--	May 30, 2006	See El Paso Corp.
El Paso Tennessee Pipeline Co.	B+/Positive/--	B/Positive/--	May 30, 2006	See El Paso Corp.
Empire District Electric Co.	BBB-/Stable/--	BBB/Negative/--	May 17, 2006	The outlook is stable and incorporates the expectation of steady financial performance through its construction program and successful integration of the gas utility. In addition, Standard & Poor's Ratings Services expects that Empire will finance its capital needs in a manner that is consistent with the current rating. The outlook could be revised to negative, as a result of unfavorable regulatory actions or if the financial measures weaken from increased capital spending or higher than expected use of leverage over the next several years. The outlook could be revised to positive if rate recovery is supportive during the construction program, if a reasonable energy cost-recovery mechanism is adopted, and if financial measures begin to show sustainable improvement. The downgrade reflects Standard & Poor's view that Empire's financial measures will be constrained over the next several years by fuel and power costs that continue to exceed the level recoverable in rates, and by Empire's higher than historical level of capital spending, including the acquisition of a Missouri gas utility.
Entergy Louisiana LLC	BBB/Watch Neg/--	N.R.	May 9, 2006	The CreditWatch Negative listing reflects the potential that Hurricane Katrina's devastation may have irreparably harmed Entergy's underlying business. The economic restoration of New Orleans and the surrounding communities will clearly be painful and prolonged, and may permanently weaken Entergy's credit quality. A fundamental shift in Entergy's credit quality could precipitate lower ratings.
Green Mountain Power Corp.	BBB/Watch Pos/--	BBB/Stable/--	June 22, 2006	The ratings on Green Mountain Power Corp. were placed on CreditWatch with positive implications on June 22, 2006, following an announcement by a subsidiary of Gaz Metro Inc. (A-/Negative/--) of its agreement to acquire Green Mountain Power. The CreditWatch placement reflects the possibility that Green Mountain Power's credit profile may improve as a result its affiliation with a stronger entity.
Indianapolis Power & Light Co.	BB+/Positive/--	BB+/Stable/--	June 5, 2006	See IPALCO Enterprise Inc.
IPALCO Enterprises Inc.	BB+/Positive/--	BB+/Stable/--	June 5, 2006	The positive outlook for IPALCO reflects expectations for gradual financial improvement to levels commensurate with solid investment-grade cash flow metrics. In this regard, an upgrade could occur in the foreseeable future if the company can produce and sustain adjusted funds from operations (FFO) to total debt in the low to mid-teens percentage area and maintain its currently healthy FFO interest coverage of greater than 3x. Upward ratings momentum also assumes continuation of supportive Indiana regulatory practices, such as the environmental compliance cost-recovery tracker, and no material increase in debt leverage. If the company does not achieve stronger financial results in the near term, the outlook will be revised to stable.
ITC Holdings Corp.	BBB/Watch Neg/--	BBB/Stable/--	May 12, 2006	Standard & Poor's Ratings Services placed the 'BBB' corporate credit ratings and debt ratings on ITC Holdings Corp. and its utility subsidiary International Transmission Co. on CreditWatch with negative implications, following the announcement that it will acquire Michigan Electric Transmission Company LLC (METC) for $866 million plus $49 million of transaction costs. METC's assets consist principally of the former transmission assets of Consumers Energy Co. (BB/Stable/--).
International Transmission Co	BBB/Watch Neg/--	BBB/Stable/--	May 12, 2006	See ITC Holdings Corp.
Kinder Morgan Inc.	BBB/Watch Neg/A-2	BBB/Negative/A-2	May 30, 2006	Standard & Poor's Ratings Services placed its 'BBB' long-term corporate credit rating on Kinder Morgan Inc. (KMI) and subsidiaries and its 'BBB+' long-term corporate credit rating on master limited partnership Kinder Morgan Energy Partners L.P. (KMP) on CreditWatch with negative implications, following the announced offer by a group of Kinder Morgan management and private investors to buy all of KMI's outstanding common shares. Standard & Poor's also placed its 'A-2' short-term corporate credit rating on KMI on CreditWatch with negative implications and affirmed its 'A-2' short-term corporate credit rating on KM. KMI and KMP have about $13 billion of debt. The negative CreditWatch listing for KMI is prompted

				by the group's plans to noticeably increase its financial leverage to fund the purchase. The negative CreditWatch listing for KMP reflects its legal, strategic, and business ties to KMI. The offer to take KMI private has not yet been evaluated or approved by KMI's board of directors. If the proposal goes forward, our evaluation of the entire Kinder Morgan enterprise to resolve the CreditWatch listings will focus on the greater debt burden and future composition of business activities at KMI, and any legal or governance changes at KMP that may affect our view of the ratings linkage between the two entities.
NSTAR	A+/Stable/A-1	A/Positive/A-1	May 17, 2006	The rating action reflects the ongoing constructive regulatory environment, the company's low-operating risk electricity and natural gas distribution and transmission operations, and expectations of sustained strong credit metrics stemming from the recently approved rate agreement.
NSTAR Gas Co.	A+/Stable/--	A/Positive/--	May 17, 2006	See NSTAR
New York Water Service Corp.	BB/Watch Pos/--	BB/Stable/--	May 16, 2006	The 'BB' corporate credit rating is on CreditWatch with positive implications. The rating action is in response to the announcement that regulated water utility Aqua America Inc. (unrated) has reached an agreement with Utilities & Industries Corp. LLC (unrated) to acquire New York Water. The transaction is valued at $51 million, of which Aqua America will pay $28 million in cash to acquire the stock of the company and assume $23 million in debt. The acquisition is subject to approval by the New York Public Service Commission, and Aqua America anticipates closing the transaction by the end of the year.
Northern Border Pipeline Co.	A-/Stable/--	BBB+/Watch Pos/--	May 15, 2006	See ONEOK Inc.
Northwest Pipeline Corp.	BB-/Positive/--	B+/Positive/--	May 4, 2006	See Williams Cos.
NorthWestern Corp.	BB+/Watch Neg/--	BB+/Watch Dev/--	April 26, 2006	The ratings on NorthWestern Corp. were originally placed on CreditWatch with developing implications on Dec. 6, 2005, after Black Hills Corp. offered to acquire NorthWestern. Based on Babcock & Brown Infrastructure Ltd.'s (BBI) investor presentation, it expects to fund the acquisition by issuing $505 million of new debt at an intermediate holding company and a mix of funds from the BBI level. Also, BBI would assume roughly $740 million of existing NorthWestern debt. The negative CreditWatch listing reflects our opinion that NorthWestern's credit measures, which now adequately support the 'BB+' rating, would weaken after the transaction closes due to the incremental $505 million of debt. Standard & Poor's will resolve the CreditWatch listing after fully reviewing BBI, the final financing of the acquisition, and NorthWestern's resulting creditworthiness.
NSTAR	A+/Stable/A-1	A/Positive/A-1	May 17, 2006	The stable outlook reflects Standard & Poor's Ratings Services' expectation that NSTAR will continue to pursue low-operating transmission and distribution activities while preserving its strong financial profile. Furthermore, Standard & Poor's expects the regulatory environment to continue to be supportive of credit quality, and that recovery of all deferred stranded costs will occur by the end of the current rate agreement, preserving the company's financial profile. A positive outlook, while not contemplated currently, will most likely depend on further improvement in the financial profile. At the same time, the outlook could be revised to negative if the financial performance weakens, mainly as a result of weaker than anticipated cash flow stemming from the transition-cost deferrals.
NSTAR Gas Co.	A+/Stable/--	A/Positive/--	May 17, 2006	See NSTAR
ONEOK Inc.	BBB/Stable/A-2	BBB/Watch Neg/A-2	May 15, 2006	The rating actions reflect Standard & Poor's Ratings Services' assessment of ONEOK's transfer of its midstream assets to Northern Border Partners L.P. (NBP), the companies' reconfigured business strategy, and the effect on NBP, Northern Border Pipeline Co. (NBPL), and, ultimately, ONEOK. The ratings affirmation on ONEOK reflects its continued, satisfactory business risk profile and intermediate financial profile, and factored in its use of a portion of its proceeds from the asset transfer to repay short-term debt. The downgrade of NBP's corporate credit rating primarily reflects the greater risk of operating ONEOK's higher-risk midstream assets. Standard & Poor's also expects NBP to serve as ONEOK's primary growth vehicle and, given ONEOK's 100% general partnership interest in NBP, we view the ratings on the two entities as

				increasingly intertwined.
Orange and Rockland Utilities Inc.	A/Negative/A-1	A/Stable/A-1	June 6, 2006	See Consolidated Edison Inc.
PanEnergy Corp.	BBB/Positive/--	BBB/Stable/--	May 25, 2006	See Duke Energy Corp.
PSI Energy Inc.	BBB/Positive/A-2	BBB/Stable/A-2	May 25, 2006	See Duke Energy Corp.
Rockland Electric Co.	A/Negative/--	A/Stable/--	June 6, 2006	See Consolidated Edison Inc.
Southern Natural Gas Co.	B+/Positive/--	B/Positive/--	May 30, 2006	See El Paso Corp.
Tennessee Gas Pipeline Co.	B+/Positive/--	B/Positive/--	May 30, 2006	See El Paso Corp.
Transcontinental Gas Pipe Line	BB-/Positive/--	B+/Positive/--	May 4, 2006	See Williams Cos.
TXU Corp.	BBB-/Negative/--	BBB-/Stable/--	June 15, 2006	The outlook revision to Negative reflects the potential for increased risk to the consolidated TXU rating that could result from TXU's plan to build 11 coal-fired power plants totaling 9,079 MW, which the company expects to place into service by mid-2010 and involve an investment of over $10 billion. TXU plans to develop this investment, TXU Generation Development Co. (TXU DevCo), on a nonrecourse basis from TXU and its subsidiaries. The negative outlook does not reflect Standard & Poor's Ratings Services' view of TXU's credit risk for its current rated operations in Texas. TXU, TXU Energy, TXU Electric Delivery, and TXU U.S. Holdings are all rated on a consolidated basis.
TXU Electric Delivery Co.	BBB-/Negative/--	BBB-/Stable/--	June 15, 2006	See TXU Corp.
TXU Energy Co. LLC	BBB-/Negative/--	BBB-/Stable/--	June 15, 2006	See TXU Corp.
Union Light Heat & Power Co.	BBB/Positive/--	BBB/Stable/--	May 25, 2006	See Duke Energy Corp.
Williams Companies Inc. (The)	BB-/Positive/B-2	B+/Positive/B-2	May 4, 2006	The rating upgrade reflects Standard & Poor's Ratings Services' conclusion that Williams' financial metrics have improved significantly as a result of deveraging and improved operating performance. The positive outlook reflects the potential that the rating could be raised over the next two years, if the company achieves the forecast financial targets.

*Dates represent the period from April 7 to June 22, 2006, covered by this report card.

Ratings Trends

Chart 3

image

Selected Articles

Table 3

Previously Published Electric/Gas/Water Utilities Articles

Article title	Published date
Credit FAQ: AGL Resources Inc.	May 2, 2006
Credit FAQ: PEPCO Holdings Inc.	April 5, 2006
Credit FAQ: The Williams Cos.' Long Road To Investment Grade	May 4, 2006
Credit Implications Of Deferred Revenue For G&T Co-ops And Public Power	May 16, 2006

Energy Policy Act Of 2005 May Spark More Electric Transmission Investment In U.S.	March 30, 2006
First-Quarter U.S. Utility Upgrades Outpaced Downgrades, But Momentum Is Likely To Change	April 27, 2006
Fuel And Purchased-Power Cost Recovery In The Wake Of Volatile Gas And Power Markets-U.S. Electric Utilities To Watch	March 22, 2006
Industry Report Card: Top 48 Global Utilities	June 1, 2006
New Jersey's Power Auction Results Are Favorable For Base-Load Merchant Generators	Feb. 24, 2006
No Major Shifts In U.S. Utilities' Pension Funding Status	June 12, 2006
Pace Of U.S. Utility Rating Actions Picked Up In 2005; Downgrades Dominate	Feb. 1, 2006
Peer Comparison: North American Stand-Alone Transmission Companies Deliver Electricity...And Profits	April 26, 2006
U.S. Gas-Fired Power Plants Get A Boost From High Natural Gas Prices	March 22, 2006
U.S. Water Utilities Remain Islands of Stability.	Feb. 15, 2006
Will High-Yield Or High-Grade Financing Fuel New U.S. Coal Power Plants?	Jan. 10, 2006

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Table 4

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Comments and ratings reflect available public data as of July 10, 2006.

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RESEARCH

No Major Shifts In U.S. Utilities' Pension Funding Status

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Standard & Poor's Rating Services has begun including standard post-retirement obligation adjustments in its calculation of regulated utility issuers' financial statistics. Because pension and other postretirement benefit obligations are ultimately recoverable in rates, shortfalls are not considered to be an acute credit factor, and Standard & Poor's historically has not adjusted its ratios for these items. These adjustments will now appear in our published reports for regulated utilities.

The most common postretirement obligations are pensions and retiree medical benefits. We have always ˥owledged that large underfunded postretirement obligations could lead to a loss of flexibility for a .y in the long run, and have always incorporated this in our analyses. Therefore, we do not expect ratings will change solely because of this modification.

However, if Standard & Poor's is not comfortable with the ultimate recoverability of a shortfall in rates, this will negatively affect the business risk profile. Meanwhile, if utilities have booked a regulatory asset, and Standard & Poor's is comfortable with the ultimate recoverability of that regulatory asset, it will positively affect the business profile score.

After reviewing pension funding status for regulated entities for three consecutive years, we have concluded that overall funding levels have been quite static over that time frame. Since last year, pension funded status appears to have shifted marginally lower when looking at the distribution of funded status of all the companies, however, on an aggregate basis the funded status is virtually unchanged. Regulated utility companies, unlike industrial companies operating in the competitive marketplace, usually can collect pension expenses in rates. These expenses are included when a utility files a rate case. However, for companies operating under long-term rate freezes or for companies that do not plan to file rate cases in the near term, the inability to collect the appropriate amount of pension expense in rates may lead to diminished credit-protection measures. Also, some may make cash contributions to the pension fund assets. These contributions may divert cash flow intended for other purposes, necessitating borrowing to meet obligations the company had expected to be paid through operating cash flows.

Standard & Poor's financial adjustments for postretirement obligations are fully described in two articles, "Corporate Ratings Criteria--Postretirement Obligations," published Oct. 28, 2004, which was updated by, "CreditStats: Standard & Poor's Revises Statistical Practices," published May 15, 2006.

The analytical adjustments that we make are:

- Debt adjustment. We treat unfunded pension liabilities, health care obligations, and other deferred benefits as debt-like. To simplify this analysis, we net all benefit plan assets and liabilities, combining a company's overfunded plans with its underfunded plans. We use the fullest measure of the unfunded liability available, generally the projected benefit obligation for pensions. Finally, we factor in an income tax benefit, reducing the liability by a tax benefit calculated at the marginal tax rate.
- Equity adjustment. Standard & Poor's increases or reduces equity by the net amount that the funded status of postretirement obligations exceeds or falls below the amounts recorded on the balance sheet. This amount is also reduced for an income tax benefit, calculated at the marginal tax

rate.

- Operating results adjustment. Standard & Poor's only considers pension service cost in calculating operating income. In this adjustment, we remove all amounts related to interest, return on plan assets, actuarial gains and losses, past service costs, settlements, and curtailments, leaving only service costs. This change is not adjusted for income taxes.
- Interest expense adjustment. Pension interest expense, which is the increase in the present value of the pension liability related to the passage of time and the assumed discount rate, is essentially a financing cost and is reclassified as such. Interest expense is reduced, but not below zero, by the return on pension assets. This adjustment is calculated twice, first using the normalized (or expected) return on pension plan assets and second using the actual return on assets. The normalized calculation reduces volatility caused when actual returns on assets differ widely from year to year. This change is not adjusted for income taxes.
- Funds from operations (FFO) adjustment. FFO is defined as net income from operations plus depreciation and amortization, deferred income taxes, and other noncash items. Standard & Poor's makes an additional adjustment to FFO for pension contributions. FFO will include, on a tax-effected basis, the total of service and interest costs, reduced by the return on pension plan assets. Cash payments in excess of this amount are considered to be debt repayment, and cash payments below this amount are considered to be borrowings. This adjustment is also calculated twice, first using the normalized (or expected) return on pension plan assets and second using the actual return on assets.

In September 2004 and May 2005, Standard & Poor's published summaries of U.S. utility pension and other postretirement benefit obligations. The purpose of these articles was to highlight trends in funding status and to benchmark pension and postretirement benefit status and assumptions for regulated entities. The companies in the database are regulated distributors of electricity and/or natural gas, integrated 'ectric and natural gas utilities, and diversified energy companies that focus on regulated electricity and s operations. The database consists of diversified holding companies and stand-alone entities that are .ot part of a larger holding company, and includes 91 companies (see Appendix).

To determine which companies might have larger adjustments as a result of using pension adjusted ratios in published numbers, we calculated the total pension and other postretirement benefit shortfall as a percentage of total assets in 2005. The top 10 companies are displayed in table 1, while table 2 shows three key credit metrics on an unadjusted basis for these companies, together with these metrics adjusted for unfunded pension and postretirement obligations.

Table 1

Top 10 Pension Plus OPEB Shortfalls As A Percent Of Total Assets

	Funded status (mil. $)				
	Pension	**OPEB**	**Total**	**Total assets (mil. $)**	**Total shortfall as a % of total assets**
Central Hudson Gas & Electric Corp.	(60)	(88)	(148)	1,121	13.23
National Fuel Gas Co.	(209)	(275)	(483)	3,723	12.98
Madison Gas & Electric Co.	(57)	(46)	(103)	914	11.22
Central Vermont Public Service Corp.	(36)	(24)	(60)	551	10.9
ALLETE Inc.	(75)	(76)	(151)	1,399	10.82
KeySpan Corp.	(502)	(945)	(1,446)	13,813	10.47
El Paso Electric Co.	(81)	(88)	(169)	1,665	10.16
National Grid USA	(848)	(1,097)	(1,945)	20,712	9.39
WGL Holdings Inc.	1	(207)	(207)	2,446	8.46
Laclede Group Inc.	(54)	(39)	(93)	1,227	7.61

OPEB--Other postemployment benefits.

Table 2

Credit Measures Pre- And Post-Pension Adjustment

	Total debt to total capital (%)			FFO to total debt (%)			FFO to interest		
	Pre-pension adjs.	**Pension adjusted**	**Difference**	**Pre-pension adjs.**	**Pension adjusted**	**Difference**	**Pre-pension adjs.**	**Pension adjusted**	**Difference**
Central Hudson Gas &	56.2	68.0	11.8	17.1	13.1	(4.0)	4.5	3.8	(0.7)

Electric Corp.									
National Fuel Gas Co.	48.7	59.8	11.1	33.2	28.2	(5.0)	5.5	5.9	0.4
Madison Gas & Electric Co.	48.2	54.4	6.2	22.7	18.4	(4.3)	5.8	5.2	(0.6)
Central Vermont Public Service Corp.	65.9	70.5	4.6	6.6	6.3	(0.3)	2.1	1.8	(0.3)
ALLETE Inc	46.9	54.3	7.4	14.3	11.7	(2.6)	3.3	3.2	(0.1)
KeySpan Corp.	52.9	61.0	8.1	19.5	16.5	(3.0)	4.2	4.1	(0.1)
El Paso Electric Co.	53.2	57.7	4.5	29.3	26.0	(3.3)	5.8	5.8	0.0
National Grid USA	38.5	46.3	7.8	28.8	24.2	(4.6)	6.1	6.1	0.0
WGL Holdings, Inc.	43.4	52.4	9.0	28.8	25.7	(3.1)	5.4	5.6	0.2
Laclede Group Inc	56.9	67.3	10.4	14.1	14.8	0.7	3.3	3.3	0.0

As can be seen in table 1, eight of the top 10 companies are relatively small in terms of total assets. While their funding statuses in absolute dollars are not especially large, the size of the shortfall as compared with the size of the company is large. Indeed, as seen in table 2, Central Hudson Gas and National Fuel Gas each show debt to capital more than 11% higher after adjusting for pension and other postemployment employee benefits (OPEB) shortfalls. Central Hudson collects funds for its pension plan in rates. To the extent that pension expense and postretirement benefits increased to amounts beyond what is captured in rates, Central Hudson does not need to expense the undercollection. Instead, the difference between the actual amounts and those collected in rates is deferred in the form of a regulatory asset, based on the anticipation that the difference will be collected in the future. From a credit perspective, the regulatory deferral provides the utility with some assurance that costs incurred today and funded with operating cash flow will be recovered in the future along with any associated carrying costs.

an be seen in table 2, the size of the adjustments is not directly related to the size of the shortfall as a centage of total assets. This is because the adjustment is a function of not just the underfunded amount, but also of the portion of the underfunded amount that is already reflected on the balance sheet.

In addition, in some cases FFO/debt and FFO/interest actually improve on an adjusted basis. This is because the adjustment to FFO will be positive if cash payments to the plan are greater than the tax-affected total of service and interest costs, reduced by the return on pension plan assets. Of course, utilities do not always wait to collect the underfunded amounts. In the first quarter of 2005, Exelon Corp. entered into a $2 billion term loan agreement to fund pension contributions. In this case, the off-balance-sheet pension obligation was in fact converted to on-balance-sheet debt. Also, CenterPoint Energy used about $400 million of the proceeds of its sale of Texas Genco Holdings Inc. to fund pension contributions. This reduced the amount of debt reduction possible from the proceeds from that sale. The contribution also allowed CenterPoint to move from a substantially underfunded position to a virtually fully funded position. These are not the only examples, but clearly, underfunded pension obligations affected these companies' decisions as to how to allocate capital.

Although companies can fund pensions through rates, the funding of large shortfalls may not be palatable for regulators. Ultimately, the unfunded obligations will lead to higher rates or strained regulatory relations. If Standard & Poor's is not comfortable with the ultimate recoverability of a shortfall in rates, this will negatively affect the utility's business profile score. Meanwhile, if utilities have booked a regulatory asset, and Standard & Poor's is comfortable with the ultimate recoverability of that regulatory asset, it will positively affect the business profile score.

Aggregate Pension And OPEB Funding

A review of the 91 companies in the database concludes that there is no material deviation in the pension assumptions and pension and OPEB funded status over last year. The aggregate pension funding ratio, which is the fair value of the plan assets divided by the projected benefit obligation, increased marginally to [illegible]% in 2005 from 88.5% in 2004. The chart displays the distribution of pension-funded status over the ompanies. On an aggregate basis, there appears to be a shift toward less funded levels, with 13% overfunded in 2005 versus 14% in 2004, and 36% below 80% funded in 2005 versus 30% in 2004. Because the aggregate funding level is virtually unchanged, this would imply that larger companies may be improving their funded status, while more of the smaller companies are seeing their funded status fall. Exelon's large contribution is a case-in-point.

image

Individual Company Status

As previously discussed, regulated utility companies usually can collect pension expenses in rates. However, some may make cash contributions to the pension fund assets in excess of amounts collected through rates, necessitating borrowing to meet obligations the company had expected to be paid through operating cash flows. To highlight companies for which such shortfalls may become an issue, Standard & Poor's examined funding ratios, pension and total postretirement benefit shortfalls, and such shortfalls as a percentage of total debt.

While the aggregate pension funding ratio for the utility group was 88.9% in 2005, pension funding ratios range from 60% to 195%. Table 3 displays the top-five and bottom-five companies for pension funding ratios, respectively.

Table 3

Top Five And Bottom Five Pension Funding Ratios In 2005

	Plan assets (mil. $)	Projected benefit obligation (mil. $)	Ratio (%)
Five lowest funding ratios			
PacifiCorp	806.5	1,338.1	60.3
El Paso Electric Co.	123.5	204.7	60.3
nergy Corp.*	1,169.0	1,898.0	61.6
MS Energy Corp.	1,018.0	1,601.0	63.6
Black Hills Corp.	59.3	93.1	63.7
Five highest funding ratios			
FPL Group Inc.	3,120.0	1,599.0	195.1
Nicor Gas Co.	424.0	284.4	149.1
SCANA Corp.	854.3	711.5	120.1
Dominion Resources Inc.	4,360.0	3,834.0	113.7
Southern Co.	6,147.0	5,557.0	110.6

*Cinergy Corp. has completed its merger with Duke Energy Corp. and will not be part of this database on a stand-alone basis going forward.

More telling is the measurement of total shortfalls as compared with the companies' size as measured by total assets (discussed above and displayed in table 1). This measurement provides a benchmark for how large a relative off-balance-sheet obligation is represented by the pension and OPEB shortfall. For example, Black Hills Corp.'s pension-funding ratio is among the lowest at 63.7%. However, its pension shortfall represents only 1.6% of the company's total assets. The aggregate pension shortfall for the companies analyzed was $15.2 billion in 2005, as compared with $15.3 billion in 2004. The total pension and OPEB shortfall was $40.5 billion, as compared with $40.3 billion in 2004. Clearly, OPEB underfunding is substantially greater than pension underfunding. Interestingly, 37% of the pension shortfall comes from the companies with the five largest pension shortfalls, while only 26% of the total pension and OPEB shortfall comes from the companies with the five largest total pension and OPEB shortfalls.

Tables 4 and 5 display the companies with the highest liabilities. The Tennessee Valley Authority ranked first in the largest pension shortfall category while Exelon, which ranked first in 2004, improved due to its $2 billion cash contribution. However, when including both pension and OPEB funding, Exelon's shortfall remains the largest, and if its merger with Public Service Enterprise Group goes forward, the consolidated entity's shortfall will be quite large on an absolute basis. FirstEnergy Corp. has continuously improved its pension plus OPEB shortfall, which is down to $1.54 billion in 2005 from $1.76 billion in 2004 and $2.68 billion in 2003.

ble 4

Companies With The Largest Pension Shortfalls

	Pension shortfall (mil. $)

2005	
Tennessee Valley Authority	1,418
PG&E Corp.	1,200
Exelon Corp.	1,187
Entergy Corp.	899
National Grid USA	848
2004	
Exelon Corp.	2,761
Tennessee Valley Authority	1,338
PG&E Corp.	943
National Grid USA	776
Entergy Corp.	761

Table 5

Companies With The Largest Pension Plus OPEB Shortfalls

	Pension shortfall (mil. $)
2005	
Exelon Corp.	3,143
Tennessee Valley Authority	1,962
Public Service Enterprise Group	1,750
DTE Energy Co.	1,741
ergy Corp.	1,663
2004	
Exelon Corp.	4,503
Tennessee Valley Authority	1,785
FirstEnergy Corp.	1,761
American Electric Power Co. Inc.	1,560
Public Service Enterprise Group	1,519

OPEB--Other postemployment employee benefits.

Appendix

Table 6

Companies In Pension Database

1	AGL Resources Inc.	50	National Grid USA
2	Allegheny Energy Inc.	51	Nicor Gas Co.
3	ALLETE Inc.	52	NiSource Inc.
4	Alliant Energy Corp.	53	Northeast Utilities
5	Ameren Corp.	54	NorthWestern Corp.
6	American Electric Power Co. Inc.	55	Northwest Natural Gas Co.
7	Aquila Inc.	56	NSTAR
8	Atmos Energy Corp.	57	OGE Energy Corp.
9	Avista Corp.	58	ONEOK Inc.
10	Black Hills Corp.	59	PacifiCorp
11	Cascade Natural Gas Corp.	60	Pacific Gas & Electric Co.
12	CenterPoint Energy Inc.	61	Peoples Energy Corp.
13	Central Hudson Gas & Electric Corp.	62	PEPCO Holdings Inc.
14	Central Vermont Public Service Corp.	63	Piedmont Natural Gas Co. Inc.
15	Cinergy Corp.	64	Pinnacle West Capital Corp.
	Cleco Corp.	65	Public Service Co. of New Mexico
	CMS Energy Corp.	66	Portland General Electric Co.
18	Consolidated Edison Inc.	67	PPL Corp.
19	Constellation Energy Group Inc.	68	Progress Energy Inc.

20 Dominion Resources Inc.
21 Duquesne Light Holdings Inc.
22 DTE Energy Co.
23 DPL Inc.
24 Duke Energy Corp.
25 Dynegy Inc.
26 Edison International
27 El Paso Electric Co.
28 Empire District Electric Co.
29 Energen Corp.
30 Energy East Corp.
31 Entergy Corp.
32 Equitable Resources Inc.
33 Exelon Corp.
34 FirstEnergy Corp.
35 FPL Group Inc.
36 Great Plains Energy Inc.
37 Green Mountain Power Corp.
38 Hawaiian Electric Industries Inc.
39 IDACORP Inc.
40 IPALCO Enterprises Inc.
41 Kentucky Utilities Co.
42 KeySpan Corp.
Kinder Morgan Inc.
Laclede Group Inc.
45 Louisville Gas & Electric Co.
46 Madison Gas & Electric Co.
47 MDU Resources Group Inc.
48 MidAmerican Energy Holdings Co.
49 National Fuel Gas Co.
69 Public Service Enterprise Group Inc.
70 Puget Energy Inc.
71 Questar Corp.
72 SCANA Corp.
73 SEMCO Energy Inc.
74 Sempra Energy
75 Sierra Pacific Resources
76 South Jersey Gas Co.
77 Southern Co.
78 Southern Union Co.
79 Southwest Gas Corp.
80 TECO Energy Inc.
81 Tennessee Valley Authority
82 Texas-New Mexico Power Co.
83 Unisource Energy Corp.
84 TXU Corp.
85 Vectren Corp.
86 Westar Energy Inc.
87 WGL Holdings Inc.
88 Williams Cos. Inc. (The)
89 Wisconsin Energy Corp.
90 WPS Resources Corp.
91 Xcel Energy Inc.

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Hawaiian Electric Company, Inc.
Financial Ratios

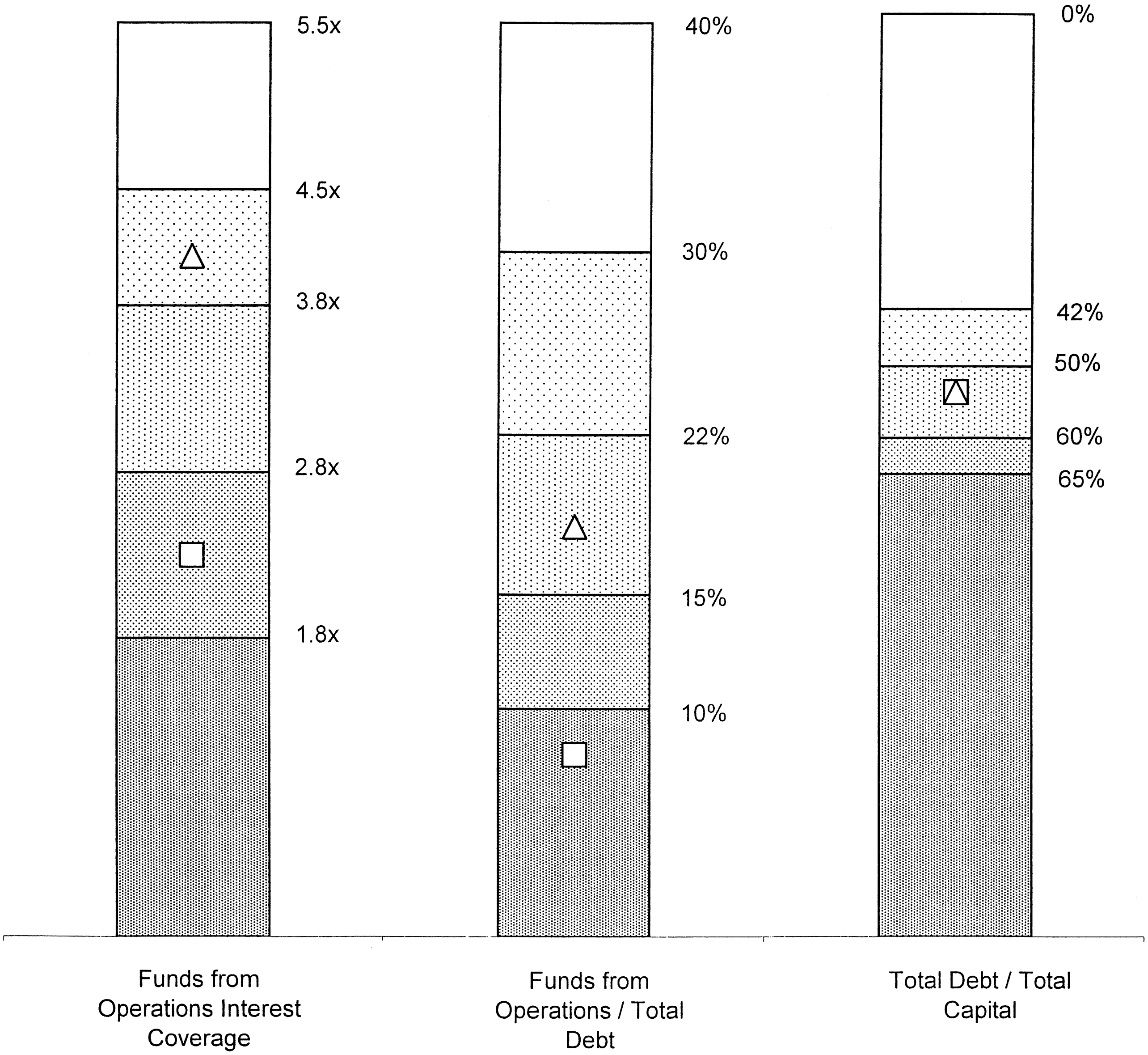
Test Year 2007	NO Rate Increase	WITH Rate Increase
Funds from Operations Interest Coverage *	2.34 x	4.05 x
Funds from Operations / Average Total Debt *	8%	18%
Total Debt / Total Capital *	54%	54%
Total Debt / Total Capital without Purchased Power Debt Equivalent	45%	45%

2005 Actual	
Total Debt / Total Capital *	57%
Total Debt / Total Capital without Purchased Power Debt Equivalent	47%

* These ratios take into account the debt equivalent (off-balance sheet purchased power and operating lease obligations).

Financial Ratios in Comparison to S&P Rating Guidelines

Business Profile = 5



	Funds from Operations Interest Coverage	Funds from Operations / Total Debt	Total Debt / Total Capital
HECO w/ Rate Increase	4.1 x	18%	54%
HECO w/out Rate Increase	2.3 x	8%	54%

- AA
- A
- BBB
- BB
- Below BB
- Δ HECO with Rate Increase
- □ HECO without Rate Increase

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RESEARCH

Hawaiian Electric Company, Inc.

Publication date: 31-May-2006
Primary Credit Analyst: Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com

Corporate Credit Rating

BBB+/Negative/A-2

Business risk profile

1 2 3 4 $\boxed{5}$ 6 7 8 9 10

Financial risk profile:
Moderate

Debt maturities:
Hawaiian Electric Co. Inc. has no maturing long-term debt until 2012. Scheduled maturities are $57.5 million in 2012, $11.4 million in 2014, and $50 million in 2018. Its remaining maturities of $650.5 million occur in 2020 and beyond. Hawaiian Electric Industries Inc. (parent company of Hawaiian Electric) has scheduled maturities of long-term debt of $10 million in 2007, $50 million in 2008. It's remaining maturities of $207 million occur in 2011 and beyond.

Outstanding Rating(s)

Hawaiian Electric Company, Inc.	
Sr unsecd debt	
Local currency	BBB+
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
Hawaiian Electric Industries Inc.	
Corporate Credit Rating	BBB/Negative/A-2
Sr unsecd debt	
Local currency	BBB
Pfd stk	
Local currency	BB+
American Savings Bank, FSB, Honolulu HI	
Corporate Credit Rating	BBB-/Positive/A-3
Certificate Of Deposit	
Local currency	BBB-/A-3
Hawaii Electric Light Company, Inc.	
Corporate Credit Rating	BBB+/Negative/--
Sr unsecd debt	
Local currency	BBB+
Maui Electric Company, Ltd.	
Corporate Credit Rating	BBB+/Negative/--
Sr unsecd debt	
Local currency	BBB+

Corporate Credit Rating History

Nov. 16, 1990	A-/A-2
Feb. 9, 1993	BBB+/A-2

Major Rating Factors

Strengths:

- Generally responsive regulatory climate with an excellent fuel clause,
- Limited competitive threats due to the lack of interconnections and wheeling capability, and
- Little asset concentration risk.

Weaknesses:

- Dependence on supportive rate decisions to strengthen financial condition,
- An undiversified economy,
- Large purchased power obligations and dependence on imported fuel oil, and
- Strained consolidated financial metrics.

Rationale

The ratings on Hawaiian Electric Co. Inc. are based on the consolidated credit profile of Hawaiian Electric Industries Inc. (HEI), which includes Hawaiian Electric's utility operations and its two utility subsidiaries (82% of core revenues and 61% of operating income as of Dec. 31, 2005), and the riskier financial services operations of American Savings Bank FSB (18% of core revenues and 39% of operating income). Standard & Poor's Ratings Services does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI.

HEI's consolidated financial condition remains somewhat weak for the rating despite the strong Hawaii economy and the company's efforts in recent years to strengthen its capital structure. Financial metrics have been pressured owing to rising operating and maintenance expenses, increasing capital outlays, and the prolonged lack of rate relief. Absent a responsive final rate order in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate with the current ratings.

HEI has a satisfactory business profiles of '6' (business profiles are ranked from '1' (excellent) to '10' (vulnerable)) and subpar financial measures. HEI's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, an excellent fuel clause, and steady banking operations. The bank's consistent earnings are driven by net interest income from its low-cost deposit funding and low-risk earning-asset base. These strengths are tempered by Hawaii's economic dependence on a limited number of industries, reliance on fuel oil, significant purchased power obligations, and support of the somewhat riskier banking businesses.

On a stand-alone basis, Hawaiian Electric has a healthier financial profile and slightly stronger business profile ('5') than HEI owing to a lower debt burden and the absence of nonutility operations.

A responsive final rate order from the Hawaii Public Utilities Commission (PUC) with regard to Hawaiian Electric's pending rate case is crucial to help lift key financial measures to more appropriate levels for the ratings. In September 2005, the PUC issued an interim net rate hike of $41.1 million (3.3%) that is marginally supportive of current ratings. If the amount collected under the interim increase exceeds the amount of the increase ultimately approved in the PUC's final decision and order, the company must refund the excess to its ratepayers with interest. A final order that closely mirrors the interim ruling appears to be sufficient to lift key financial metrics to levels that are marginally suitable for Standard & Poor's guideposts for the 'BBB' rating category. There are no time restrictions in which the PUC must issue a final order.

Hawaii's economy grew by about 3.8% in 2005, and is expected to grow by 3.0% in 2006. Military and federal government spending remains strong as the U.S. Department of Defense has moved military assets to Hawaii. Tourism is also a significant component of the Hawaii economy and set a record for arrivals in 2005, with visitor days up 6.6%. Strength in key nontourism sectors, particularly real estate and the growing military commitment, coupled with low interest rates, have resulted in solid construction and real estate sales activity although future growth in real estate may slow with rising interest rates. Hawaii's economic growth is expected to be tied primarily to the rate of expansion in the mainland U.S. and Japan economies and increased military spending, yet remains vulnerable to uncertainties in the world's geopolitical environment.

Hawaiian Electric's projected capital outlays in 2006-2010 will focus predominantly on additions and improvements to transmission and distribution facilities (approximately 51%) and on generation projects (approximately 41%). The balance is for general plant, energy solutions, and customer-choice technologies. Internally generated cash is expected to satisfy the bulk of construction expenditures for that period.

HEI has certain bondholder protection metrics that are subpar for the current ratings. In this regard, total debt to capital (adjusted for off-balance-sheet obligations, such as purchased-power contracts and trust-originated preferred securities) and funds from operations (FFO) to total debt are somewhat weak at about 56% and 19%, respectively. Adjusted FFO interest coverage remains healthy at roughly 4.0x. Accordingly, a supportive final rate order, continued tight cost controls, improved earnings, and credit supportive actions by management will be required to lift the company's overall financial profile to more suitable levels.

Short-term credit factors
The short-term corporate credit and commercial paper ratings on HEI and Hawaiian Electric are 'A-2', incorporating solid liquidity, a manageable maturity ladder, and the ability to internally fund a large portion of dividends and capital expenditures in nearby years.

On April 3, 2006, HEI entered into a new five-year $100 million unsecured revolving credit facility and a $75 million unsecured bilateral revolver which terminates on Dec. 27, 2006. The covenants require HEI to maintain a nonconsolidated capitalization ratio of 50% or less and consolidated net worth of $850 million. The company is comfortably in compliance with these covenants. HEI used the new facilities to support the issuance of commercial paper to refinance its $100 million medium term notes that matured on April 10, 2006. Standard & Poor's expects the company to permanently fund the maturity in the foreseeable future.

Furthermore, on April 3, 2006, Hawaiian Electric entered into a new $175 million revolver that expires on March 29, 2007, but will automatically extend to five years if the longer-term agreement is approved by the PUC. Pursuant to the agreement, the company must maintain a consolidated common stock equity to capitalization ratio of at least 35%, with which the company is compliance.

Both HEI's and Hawaiian Electric's facilities support the issuance of CP, but may also be drawn for general corporate purposes. Hawaiian Electric's facility may also be drawn for capital expenditures. The facilities do not contain interest coverage ratio requirements, material adverse change clauses, nor rating triggers. As of May 1, 2006, both HEI's and Hawaiian's credit facilities were undrawn.

HEI has a manageable maturity ladder, with just $10 million due in 2007. Hawaiian Electric has no maturing long-term debt until 2012. As of March 31, 2006, HEI had $1.4 million of cash and cash equivalents (excluding American Savings Bank's cash and cash equivalents).

Standard & Poor's expects nearly 80% of Hawaiian Electric's 2006 construction program to be internally funded. Importantly, ongoing growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows and the bank to maintain normal cash dividend levels (54% of its earnings) while still supporting its own business growth. When the bank reaches a 7.5% core capital ratio on a sustainable basis, which is expected by June 30, 2006, it will begin to pay nearly all of its earnings as dividends to HEI.

HEI has $150 million of debt capacity remaining under a Rule 415 shelf registration and $96 million remains on an omnibus shelf registration.

Outlook

The negative outlook on Hawaiian Electric mirrors that of HEI and reflects the parent's subpar consolidated financial condition. Failure to strengthen key financial parameters, especially cash flow coverage of debt, a slump in the Hawaii economy, a punitive final rate order, and, although not expected, erosion in American Savings Bank's creditworthiness could lead to lower ratings. Conversely, credit-supportive actions by the company as well as responsive rate treatment would lead to ratings stability.

Accounting

HEI reports its financial statements in accordance with U.S. GAAP. Importantly, there was no material weakness identified by the management in its internal control over financial reporting as of Dec. 31, 2005. Recently adopted accounting standards did not have a material effect on the company's financial statements. However, the new accounting exposure draft on retirement benefits will have a significant effect on the company's financial statements if adopted.

A few of the independent power producers (IPPs) that supply power to Hawaiian Electric have declined to provide the information necessary for Hawaiian Electric to determine the applicability of FIN 46R related to the consolidation of variable interest entities (VIES). Hence, the company was unable to apply FIN 46R to these IPPs. Hawaiian Electric's other IPPs are either not VIES or outside the purview of FIN 46R.

Standard & Poor's has made certain analytical adjustments to HEI's reported financial information to reflect off-balance-sheet obligations (OBS), such as purchased power commitments and operating leases, when calculating its adjusted financial ratios.

As of Dec. 31, 2005, Hawaiian Electric had purchased power arrangements for 540 MW of firm capacity. To analyze the financial impact of purchased power contracts, Standard & Poor's calculates the net present value of future annual capacity payments (discounted at the company's average costs of debt in 2005 of about 6%) as a potential debt equivalent. Then, Standard & Poor's adds to the balance sheet only a portion of this amount, recognizing that such contractual arrangements are not entirely the equivalent of debt. The percentage that is added (the risk factor) is a function of Standard & Poor's qualitative analysis of the specific contracts and the extent to which market, operating, and regulatory risks are borne by the utility. Standard & Poor's has assigned a risk factor of 30% to Hawaiian Electric's take-and-pay contracts, which translates into a debt equivalent of $282 million.

The present value of the HEI's operating leases is determined using a 6% discount rate and is treated as a debt equivalent. We also compute operating lease interest and depreciation expenses. The amounts relating to operating leases that we included in HEI's adjusted ratios for 2005 were $111 million for OBS debt, $4.9 million for imputed interest, and $18.1 million for depreciation.

Standard & Poor's also makes an analytical adjustment for allowance for funds used during construction (AFUDC) charges capitalized by the company and treats the charges as a part of operating expenses. The AFUDC charge is backed out to arrive at cash flows from operations. Adjustments for AFUDC debt and equity in 2005 were nominal at about $2.0 million and $5.1 million, respectively.

Table 1

Hawaiian Electric Industries Inc. Peer Comparison

	--Average of past three fiscal years--			
	Hawaiian Electric Industries Inc.	**Portland General Electric Co**	**El Paso Electric Co**	**PNM Resources Inc.**
Rating	BBB/Negative/A-2	BBB+/Negative/A-2	BBB/Stable/--	BBB/Negative/A-3
(Mil. $)				
Sales	1,973.7	1,550.7	725.6	1,712.4
Net income from cont. oper.	119.0	70.7	30.1	71.5
Funds from oper. (FFO)	272.0	283.3	152.4	293.3
Capital expenditures	198.3	205.3	94.5	180.0
Cash and equivalents	169.0	145.0	23.9	32.7
Total debt	1,255.8	931.7	619.1	1,424.8
Preferred stock	34.4	0.0	0.0	12.0
Common equity	1,180.5	1,217.7	528.1	1,154.5
Total capital	2,470.7	2,149.3	1,147.2	2,591.2
Ratios				
Adj. EBIT interest coverage (x)	2.9	2.3	2.1	2.3
Adj. FFO interest coverage (x)	3.7	3.9	4.3	4.2
Adj. FFO/avg. total debt (%)	17.9	24.1	24.4	19.4
Net cash flow/capital expenditures (%)	83.0	111.2	161.8	135.9
Adj. total debt/capital (%)	57.1	49.3	54.1	59.9
Return on common equity (%)	9.2	5.8	4.9	6.2
Common dividend payout (%)	79.8	71.1	0.0	59.1

Table 2

Hawaiian Electric Industries Inc. Financial Summary

	--Fiscal year ended Dec. 30--				
	2005	2004	2003	2002	2001
Rating history	BBB/Negative/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Negative/A-2
(Mil. $)					
Sales	2,215.6	1,924.1	1,781.3	1,653.7	1,727.3
Net income from cont. oper.	131.2	107.7	118.0	118.2	107.7
Funds from oper. (FFO)	284.4	265.8	265.9	240.2	239.1
Capital expenditures	221.7	212.1	161.0	126.2	124.1
Cash and equivalents	151.5	132.1	223.3	244.5	450.8
Total debt	1,259.8	1,243.3	1,264.4	1,306.3	1,345.8
Preferred stock	34.3	34.4	34.4	34.4	34.4
Common equity	1,241.6	1,210.9	1,089.0	1,046.3	929.7
Total capital	2,535.7	2,488.7	2,387.9	2,387.0	2,309.8
Ratios					
Adj. EBIT interest coverage (x)	3.2	2.9	2.7	2.6	2.4
Adj. FFO interest coverage (x)	4.1	3.6	3.5	3.2	3.1
Adj. FFO/avg. total debt (%)	18.7	17.6	17.3	15.3	15.2
Adj. net cash flow/capital expenditures (%)	68.1	83.4	106.8	120.3	84.8
Adj. total debt/capital (%)	56.4	56.1	58.8	60.4	63.3
Return on common equity (%)	9.8	8.6	9.0	9.8	9.6
Common dividend payout (%)	78.7	87.1	73.6	71.8	73.1

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Request For Comments: Imputing Debt To Purchased Power Obligations

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Standard & Poor's Ratings Services is requesting comments from market participants about one specific element of its refined methodology for imputing debt to purchased power obligations involving utility companies.

Proposal Summary

Standard & Poor's is abandoning its practice of not imputing debt for purchased power agreements (PPA) with terms of three years or less. In addition, where there is a high probability that the utility will have an ongoing obligation to serve load beyond the nominal tenor of short-term contracts, which is almost always the case, Standard & Poor's is contemplating providing evergreen treatment to PPA obligations to reflect the long-term load serving obligations borne by utilities. Unless an electric utility faces a declining population or real prospects of customer migration to other suppliers, both of which are rare, any near-term or intermediate power supply contracts will need to be renewed or replaced with contracted or self-built capacity to continue to meet load obligations.

We acknowledge that the process of providing evergreen treatment to outstanding contracts is imprecise. Uncertainties surround the level of capacity prices that should be assumed and the duration for which contracts should be extended to reflect the load-serving obligation. Therefore, we welcome input on evergreen-related issues as we refine these aspects of the criteria.

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Response Deadline

Please submit your comments on this proposal through Dec. 15, 2006, to criteriacomments@standardandpoors.com

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Imputation Is Important For Credit Analysis

Standard & Poor's has for many years considered PPAs as financial obligations that electric utilities incur when they elect to purchase rather than build their own capacity, and this obligation has affected our view of utilities' creditworthiness. Standard & Poor's has historically applied a "risk factor" of 0% to 100% to the net present value (NPV) of the PPA capacity payments, and capitalized this amount. The risk factor's role is to calibrate the stringencies of debt imputation relative to our evaluation of the certainty of recovery of power purchase costs by virtue of regulatory and legislative protections. The imputation of debt and debt service is important to our credit analysis because the resulting financial adjustments affect several key credit metrics used when we assess credit quality.

The risk factor acts as a proxy for the proportion of risk borne by the utility. At 100%, all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers.

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Reviewing Existing Criteria--And A Few Refinements

From time to time, Standard & Poor's has revisited the methodology employed for making the financial adjustments that incorporate the obligations created by PPAs in its credit evaluations. This article discusses the most recent refinements. It also includes a discussion of additional areas that are under consideration as potential future refinements to our ratings methodology. While we expect very modest, if any, rating changes to result from these modifications, the proposed modifications are being disseminated in this article in the interest of ensuring the ongoing transparency of our rating methodology.

Standard & Poor's published its original PPA criteria in 1991, and provided updates in 1993 and 2003. During this time, the industry has established a very strong track record of demonstrating the viability and effectiveness of the various recovery mechanisms that state regulators have established for costs associated with contracted generation capacity. Recovery mechanisms have largely performed as intended, and related write-offs have proven to be very low. These results justify the continued application of risk factors that serve to temper, often substantially, the amount of debt imputation. Ensuring meaningful comparability in the financial commitments among utilities that are building and those that are purchasing capacity to satisfy load obligations is the rationale for our imputation of debt and debt service for PPAs. PPAs essentially represent substitutes for direct, debt-financed, capital investments. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. The analytical goal of our financial adjustments for PPAs is to reflect the fixed obligation in a way that depicts any credit exposure that is added by the presence of PPAs. That said, a PPA also shifts various risks to the supplier, such as construction risk and most of the operating risk. As a result, the principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates. While it is the utility that must of course make these payments, however, to the extent that regulators and, in certain cases, legislatures, have structured recovery to assign the burden to ratepayers, the utilities' risk diminishes.

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Refinements To The Methodology

With only modest liberalization of the treatment of PPAs, we are perpetuating the current ratings criteria. Current guidelines for utilities whose capacity payments are recovered in base rates provides for the application of a 50% risk factor to the NPV of the capacity payments. This approach will continue. The NPV is calculated using the utility's average cost of debt (excluding securitization debt), rather than the standardized 10% discount rate used previously. For purposes of adjusting cash flow measures, implied interest expense is calculated on the imputed debt amount. This is accomplished by applying the average cost of debt to the relevant year's imputed debt level.

To date, where PPA capacity costs were recovered through a fuel adjustment clause (FAC), as compared with base rate recovery, a risk factor of 30% has been generally used in lieu of the 50% risk factor. We view the recovery of the capacity component of a PPA through a FAC as providing greater certainty and timeliness than recovery through a base rate mechanism. (The base rate mechanism generally has greater potential for under-recovery due to variations in volume sales and fluctuations in fuel prices over time.) Based on the effectiveness of FAC mechanisms, we will adjust modestly the risk factor of 30% down to 25%.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still do not amount to pure FACs. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, a risk factor between the revised 25% FAC risk factor and the 50% risk factor will be employed in calculating adjusted ratios.

In those instances where recovery of PPA-related capacity costs is guaranteed by a legislative mechanism, the level of the risk factor will be determined by the timeliness provided by the legislative true-up mechanism. The strength of the mechanism can result in risk factors as low as 0% because legislatively prescribed recovery mechanisms are viewed as providing utilities with a greater level of protection than that provided by regulatory orders.

There are a number of utilities to which Standard & Poor's does not impute any PPA-related debt. Specifically, Standard & Poor's does not impute debt for supply arrangements if a utility acts merely as a conduit for the delivery of power (e.g., because it has been transformed into a pure transmission and distribution utility by regulators or legislation that has directed the divestiture of all generation assets). For example, in New Jersey, the vertically integrated utility companies were transformed into pure transmission and distribution utilities. The state commission, or an appointed proxy, leads an annual auction in which suppliers bid to serve the state's retail customers, and the utilities are protected from supplier default. In New Jersey, the power supply function of the state's utilities has essentially been reduced to the delivery of power and the collection of revenues from retail customers on behalf of the suppliers. Therefore, while Standard & Poor's has continued to impute debt to New Jersey's utilities for qualifying facility and exempt wholesale generator contracts to which the utilities are parties, we do not do so for other electricity supply contracts where the utilities merely act as conduits between the winners of the regulator's supply auction and the end-user, retail customers.

Finally, Standard & Poor's is abandoning the practice of not imputing debt for contracts with terms of three years or less. In addition to abandoning our historical three-year rule, we are contemplating applying an evergreen mechanism for short-term contracts. Because expiring contracts must be replaced with either debt-financed capacity additions or replacement PPAs for regulated utilities to meet load serving obligations, Standard & Poor's must look beyond the termination of near-term and intermediate-term contracts to approximate the fixed obligations that will succeed the current contracts in evaluating a utility's financial profile.

The process of providing evergreen treatment to outstanding contracts is imprecise. Uncertainties surround the level of capacity prices that should be assumed and the duration for which contracts should be extended to reflect the load-serving obligation. Therefore, we welcome input on evergreen-related issues as we refine these aspects of the criteria over the next 45 days.

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Adjusting Financial Ratios

Standard & Poor's determines the debt equivalence that it will add to a utility's balance sheet as a result of being a party to a PPA by calculating the NPV of the annual capacity payments over the life of the contract because it is the capacity payment that represents the vehicle that funds the recovery of the supplier's investment in the generation asset.

Where the PPA contract price is stated as a single, all-in energy price, Standard & Poor's will use a proxy capacity charge, stated in dollars per kilowatt-year, and multiply that figure by the number of kilowatts under contract. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine. This is a departure from the historical practice of simply halving all-in energy payments and assuming a one-to-one ratio of energy to capacity payments. This new element of the rating methodology will also be applied to generation with extremely low variable costs whose price is stated as an all-in energy price, such as nuclear and wind generation.

The discount rate used in calculating an NPV, imputed debt, and imputed interest expense is the utility's average interest rate on its outstanding debt (excluding securitization related debt). Standard & Poor's multiplies the NPV of the stream of capacity payments by the appropriate risk factor, which will generally be

25% for capacity payments that are recovered through fuel adjustment clauses and 50% for capacity payments that are recovered in base rates. This amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense by multiplying a given year's NPV of PPA-related capacity payments by the risk factor and the company's average interest rate on outstanding debt. The resulting number is added to reported interest expense to calculate adjusted interest coverage ratios.

Key ratios affected include:

- Balance sheet debt is increased by the calculated NPV of the stream of capacity payments, after the application of the risk factor, which is added to the numerator and denominator in calculating an adjusted debt-to-capitalization ratio;
- The implied interest expense derived from applying the average interest rate to the NPV figure is simultaneously treated as a reduction in power purchase expenses and added to interest expense for the calculation of the adjusted funds from operations (FFO) to interest ratio; and
- The FFO to total debt ratio is adjusted by adding the NPV of capacity payments, after the application of the risk factor, to debt in the denominator and an implied depreciation expense is added to FFO.

The depreciation expense adjustment, the last element of the principal financial adjustments cited above, represents a new element within the context of financial adjustments for PPAs (though it has been a long-standing component of the analytical adjustments for leases). Adding an implied depreciation expense to FFO is another element that aligns the analytical treatment of PPAs with the concept of purchased power as a substitute for self-build. The depreciation expense adjustment is a vehicle for capturing the ownership-like attributes of the contracted asset and has the effect of mitigating some of the ratio impact of debt imputation.

The mechanics of these adjustments are illustrated in the table.

Adjustments To Ratios						
(Mil. $)	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Thereafter**
Funds from operations	2,500					
Interest expense	650					
Directly issued debt	10,000					
Shareholders' equity	9,000					
Fixed capacity commitments	500	500	500	500	500	4,000
NPV of fixed capacity commitments						
Using a 6.5% discount rate	4,079					
Applying a 25% risk factor	1,020					
Unadjusted ratios						

FFO/interest (x)	4.9					
FFO/total debt (%)	25					
Debt/capitalization (%)	53					
Ratios adjusted for debt imputation						
FFO/interest (x)*	4.6					
FFO/total debt (%)¶	23					
Debt/capitalization (%)§	55					
*Adds implied interest to the numerator and denominator. Also adds implied depreciation to the numerator. ¶Adds implied depreciation to the numerator and adds implied debt to total debt. §Adds implied debt to both the numerator and the denominator.						

Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. The NPV of the PPA will typically decrease as the maturity of the contract approaches, but on a portfolio basis, the overall NPV may remain somewhat static as old contracts roll off and new ones are executed.

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Conclusion

Absent legislative assurance of recovery, or an obligation that is little more than a fiduciary role for a transmission and distribution utility, PPAs constitute a financial risk by adding fixed obligations, though history is clearly on the side of full recovery. There is ample evidence that utility regulators and commissions have intended these costs to be for the account of the ratepayer, which justifies the continued use of risk factors. The modest revisions to our methodology seek to perpetuate our use of financial adjustments that reflect the legislative and regulatory protections that mitigate regulated utilities' exposure to the fixed obligations created by PPAs.

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII

DOCKET NO. 2006-0386
APPLICATION OF HAWAIIAN ELECTRIC COMPANY, INC. FOR APPROVAL OF RATE INCREASES AND REVISED RATE SCHEDULES AND RULES

AFFIDAVIT OF WILLIAM E. AVERA, PH.D., CFA

STATE OF TEXAS)
)
COUNTY OF TRAVIS)

Before me, the Undersigned Authority, on this 18th day of December 2006, personally appeared William E. Avera, upon being duly sworn, states the following:

My name is William E. Avera. I am over the age of 21, of sound mind and competent to testify to the matters stated herein. I am a principal in Financial Concepts and Applications, Inc. (FINCAP), a consulting firm engaged in financial, economic, and policy consulting to business and government. My business address is 3907 Red River, Austin, Texas 78751. A resume containing the details of my qualifications is attached as Appendix A.

1. In December 1996, the Public Utilities Commission of the State of Hawaii (PUC) concluded an examination of the relationship between Hawaiian Electric Industries, Inc. (HEI) and Hawaiian Electric Company, Inc. (HECO), including HECO's two electric utility subsidiaries, Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO). At that time, the PUC stated its intention to evaluate the need for a comprehensive analysis of the impact that HEI's diversified activities have on the cost of capital to HECO on a case-by-case basis in future rate proceedings. The purpose of this affidavit is to evaluate any circumstances which might alter the conclusions adopted by the PUC in its last investigation or justify including a detailed review of this issue in the scope of HECO's current rate proceeding. I previously conducted similar reviews in conjunction with affidavits submitted in Docket No. 97-0346

(December 1997) on behalf of MECO, Docket Nos. 97-0420 (March 1998), 99-0207 (October 1999 and June 2000), and 05-0315 (May 2006) on behalf of HELCO, and Docket No. 04-0113 (November 2004) on behalf of HECO.

2. Based on my evaluation, I found no evidence that would modify the findings resulting from the PUC's last review of the relationship between HEI and HECO or justify a comprehensive reexamination of these issues in HECO's present rate case, especially in light of the additional complexities and costs such a study would introduce.

3. By an order dated January 26, 1993, the PUC initiated Docket No. 7591 to review the relationship between HEI and HECO. The purpose of the review was to determine whether HEI's diversified activities, management policies, operations, or business practices resulted in any negative effects on HECO, HELCO, MECO, or ratepayers. Dennis Thomas and Associates was retained by the PUC to perform the review. An examination of the effect of diversification on the cost and availability of capital to HECO was included in the scope of the investigation, with a report (Thomas Report) being issued in January 1995.

4. I was retained by Dennis Thomas and Associates and served as Team Leader, Financial Integrity and Credit Ratings. In this position, I held direct responsibility for evaluating the impact of diversification on the availability and cost of capital for HECO and its electric utility subsidiaries, with my conclusion being incorporated into the Thomas Report.

5. The Thomas Report concluded that "on balance, diversification has not hurt electric ratepayers." With respect to the availability and cost of capital to HECO, the Thomas Report found that HECO's access to capital did not suffer as a result of HEI's involvement in non-utility activities and that diversification did not permanently raise or lower the cost of capital incorporated into the rates paid by HECO's utility customers. The Thomas Report was adopted by the PUC in its entirety in December 1996. Additionally, the PUC stated that it would apply the recommendation of the Department of Defense that the utility present a comprehensive analysis of the impact of HEI on the cost of capital for the utilities on a "case-by-case" basis in the utilities' respective rate cases.

6. In assessing the likelihood that changes in circumstances might alter the conclusions of the Thomas Report, my evaluation focused primarily on events since the report was issued in January 1995, with particular emphasis on developments since my last review was completed in Docket No. 05-0315. The availability and cost of capital is a function of investors' expectations and requirements as reflected in the capital markets. In order to examine the ongoing impact of HEI's non-utility businesses on HECO's cost and availability of capital, I reviewed numerous reports of leading investment advisory services as a guide to investors' perceptions and requirements.

7. Bond ratings, and the analyses prepared by the major rating agencies, are frequently referenced by investors and provide a useful benchmark for the risks perceived in the capital markets. As I noted in my initial affidavit filed in Docket No. 99-0207, the bond ratings assigned to HECO's first mortgage bonds by the major rating agencies were unchanged from the time the Thomas Report was prepared until these securities were redeemed in December 1, 1997.

8. Events of the last several years caused investors to rethink their assessment of the relative risks associated with the electric power industry. A well-publicized energy crisis throughout the West wreaked havoc on customers, utilities, and policymakers and had dramatic repercussions for investors and utilities nationwide. The collapse of Enron and others engaged in merchant generation and energy trading and marketing increased turmoil within the industry and served to further magnify the risks associated with the power sector. Investor confidence in the electric power industry was severely shaken, leading to reduced access to capital and constrained liquidity for many utilities.

9. While the severe distortions that characterized the energy crisis of 2000-2001 have faded, investors recognize that the continuing prospect for price spikes in energy markets cannot be discounted. Apart from continued variability in wholesale power markets, in recent years utilities and their customers have also had to contend with dramatic fluctuations in fuel costs due to ongoing volatility in the spot markets, which have only been magnified by the war in Iraq and devastating hurricanes in the Gulf Coast region. In addition, policy evolution in the electric transmission segment has been wide-reaching for mainland utilities, and investors have increasingly focused on uncertainty over operating rules and market development.

10. Revised perceptions of the risks in the industry and weakened utility finances combined to produce steady erosion in credit quality throughout the electric utility industry. For example, during 2002 Standard & Poor's Corporation (S&P) recorded 182 downgrades in the electric power industry, versus only fifteen upgrades,[1] while downgrades outpaced upgrades by more than fifteen-to-one in the fourth quarter of 2003.[2] While the pace and scale of credit ratings actions has since stabilized, the majority of companies in the utility sector now fall in the triple-B rating category, with a continued negative bias in the credit outlook for the sector.[3]

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[1] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15, 2003).
[2] Standard & Poor's Corporation, "U.S. Utilities' Ratings Decline Continued in 2003, But Pace Slows," *RatingsDirect* (Feb. 2, 2004).
[3] Standard & Poor's Corporation, "First-Quarter U.S. Utility Upgrades Outpaced Downgrades, But Momentum Is Likely To Change," *RatingsDirect* (Apr. 27, 2006).

11. Although these developments focused increased attention on the potential impact of non-utility businesses on investment risk, in the immediate aftermath of the Western energy crisis, the investment community was primarily concerned with merchant generation and energy trading activities, particularly where high debt leverage was employed. For example, S&P noted that the deterioration in the utility industry's credit quality could be traced in part to:

> Heightened business risk derived from growing, debt-financed investments ... mainly in unregulated generation and energy trading and marketing activities, that have continued to severely underperform expectations.[4]

In June 2002, S&P noted that "the last 24 months have witnessed extraordinary turmoil for power and energy debt," attributing this unprecedented shift in risk perceptions to "the credit collapse of the California utilities, through the Enron bankruptcy and subsequent market disruptions for U.S. energy merchant companies."[5]

12. Since that time, many utilities have pursued a "back to basics" strategy that has emphasized the sale of non-regulated business lines, particularly energy trading and marketing, and refocused attention on regulated electric and gas utility operations. While this has generally been viewed as an effective course to reduce overall uncertainties, the investment community has increasingly recognized that regulated operations convey their own set of challenges. For example, S&P cautioned that:

> Much of the industry continues to re-emphasize core competencies, where risks are certainly more familiar, but still daunting. These include major pending regulatory decisions, the need for substantial infrastructure expenditures, fuel-cost recovery in a high-fuel-price environment, and still low, but gradually rising interest rates. In addition, event risk, specifically mergers and acquisitions, is a significant development with the repeal of the Public Utility Holding Company Act.[6]

13. In contrast to the declining credit trend experienced by the industry as a whole, the corporate credit ratings of HEI and HECO have remained stable. This relatively greater financial strength can be attributed in part to the fact that HECO and its subsidiaries have not faced the uncertainties posed by industry restructuring and volatility in wholesale power markets. In addition, effective September 30, 2001, HEI announced that it was discontinuing its international

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[4] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline In 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15. 2003).
[5] Standard & Poor's Corporation, *2002 Power & Energy Credit Conference: Beyond the Crisis* (June 12, 2002).
[6] Standard & Poor's Corporation, "First-Quarter U.S. Utility Upgrades Outpaced Downgrades, But Momentum Is Likely To Change," *RatingsDirect* (Apr. 27, 2006).

power business and stated its intention to wind down HEI Power Corp. and dispose of its assets, with the goal of refocusing attention on its core Hawaii operations.

In response to HEI's decision to discontinue its international power operations, S&P raised HEI's business profile ranking, reflecting lower consolidated business risk, and commented that:

> Given the absence of the very risky nonregulated generation operations and HEI's concentration on the regulated utility (about 70% of earnings) and banking (30%) activities, the company's business profile is now characterized as average versus below average. The stronger business profile requires less stringent financial parameters.[7]

Similarly, Moody's noted that HEI's credit profile "benefited from the company's decision to reduce its overseas exposure" and concluded that renewed focus on core utility and banking operations has the effect of "significantly lowering its risk profile."[8]

14. The investment community has also distinguished between the tumultuous events that have traumatized diversified companies in the power sector and HEI's strategy of refocusing on its Hawaii utility and banking operations. As The Value Line Investment Survey (Value Line) concluded, for example:

> The unfavorable outcomes of regulatory restructuring and the severe slump in energy trading and marketing have hurt many companies in this sector, but not HEI.[9]

Thus, while the crisis of recent years motivated power industry participants to adopt a "back-to-basics" business strategy, investors recognized that HEI had already refocused its operations by discontinuing its international power business and exiting maritime and real estate operations. At the same time, the capital markets have distinguished between HEI's American Savings Bank (ASB) subsidiary, which is regarded as a core business, and the unregulated merchant power and energy trading activities that have commanded investor scrutiny.

15. Investors generally perceive that ASB implies a level of business risk that exceeds that of HEI's regulated utility operations, but also recognize that HECO's investors and ratepayers are protected from these uncertainties. For example, while granting HEI's support of "riskier financial service operations," S&P noted

[7] Standard & Poor's Corporation, "Bulletin: Hawaiian Electric Industries Exits Nonregulated Generation," *RatingsDirect* (Nov. 1, 2001).
[8] Moody's Investors Service, "Opinion Update: Hawaiian Electric Industries, Inc.," *Global Credit Research* (Sep. 11, 2003).
[9] The Value Line Investment Survey (Nov. 15, 2002).

that structural and regulatory protections afforded HECO warranted a higher bond rating than the parent:

> In most circumstances, Standard & Poor's will not rate the debt of a wholly owned subsidiary higher than the rating of the parent. However, exceptions can be made on the basis of structural protections or regulatory insulation, or both, assuming the entity has a financial profile that supports a higher rating. In Hawaiian Electric's case, in Standard & Poor's opinion, there are adequate insulating conditions in Hawaii's statutory and regulatory framework, including orders issued by the PUC regarding the formation of HEI's holding company structure, to separate the corporate credit ratings on HEI and Hawaiian Electric by one notch.[10]

Consistent with this view, S&P also made clear that it "does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI."[11]

16. The investment community continues to evaluate HEI as a member of the utility sector. In 2002, for example, Value Line concluded that HEI stock "is suitable for traditional, income-oriented utility investors.[12] Value Line continues to include HEI within its Electric Utility (West) industry group,[13] and Robert W. Baird & Company recently affirmed that HEI is a "core utility holding."[14] Meanwhile, S&P indicated that its April 2005 decision to revise its ratings outlook for HEI and HECO from "stable" to "negative" was motivated primarily by subpar protection parameters related to regulated utility operations.[15] S&P cited financial pressures stemming from a long-term lack of rate relief, rising operating expenses, and yet to be recovered investments. At the same time, S&P has repeatedly recognized the benefit of "decent earnings" attributable to ASB's "steady banking operations."[16]

17. ASB's strategic decision to expand its commercial lending business has not generated concern from bond ratings agencies or investors, and has generally been characterized as a gradual shift in emphasis rather than a dramatic departure from past strategy. Since 2000, the percentage of ASB's loan portfolio attributable to residential mortgages has declined from 83% to 73%, while commercial lending now represents 20% of total loans outstanding. S&P, for

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[10] Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (Mar. 16, 2006).
[11] Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (Nov. 22, 2006).
[12] The Value Line Investment Survey (Feb. 15, 2002, Aug. 16, 2002).
[13] See, *e.g.*, The Value Line Investment Survey (Aug. 11, 2006).
[14] Parker, David, "HE: Mild Weather Pressures 2Q06 EPS; Maintain Outperform Rating," Robert W. Baird & Company (Aug. 2, 2006).
[15] Standard & Poor's Corporation, "Research Update: Hawaiian Electric Industries And Utility Units Ratings Affirmed; Outlook Revised To Negative," *RatingsDirect* (Apr. 22, 2005).
[16] See *e.g.*, Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (Nov. 22, 2006).

example, observed that ASB has been "slowly and conservatively" expanding its business banking and commercial real estate operations, while retaining the lower-risk profile of a more traditional thrift,[17] and S&P continues to evaluate ASB as part of the thrift sector.[18] As well, the investment community has recognized that ASB's strategy of broadening its lending into commercial loans has helped to support earnings in the face of a flattening yield curve.[19]

The conclusion that ASB's transformation from a traditional retail thrift to a full-service community bank has had no significant impact on investors' overall risk perceptions is also supported by reference to S&P's business profile ranking for HEI, which has remained stable at "6".[20] A risk profile ranking of "6" falls one notch above the midpoint of S&P's 10-point scale, which ranges from "1" (lowest risk) to "10" (highest risk).

18. While granting that banking activities involve an increment of business risk above that of regulated utility operations, the investment community also recognizes that HEI benefits through the diversification and financial support provided by these activities and generally perceives these operations as relatively conservative and stable. For example, S&P observed that:

> [O]ngoing growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows. The decrease in Hawaiian Electric's dividend to HEI is expected to be partly offset by the increase in the bank's dividend.[21]

In addition, S&P cited ASB's "consistent earnings" from its "low-cost deposit funding and low-risk earning-asset base."[22] Similarly, Moody's Investors Service noted the stability of ASB's operations and the benefits of its predictable earnings stream.[23] Other analysts have recognized that, despite the challenges posed by the current interest rate environment, ASB has continued to maintain margins and the high quality of its loan portfolio.[24] The investment community has also

[17] Standard & Poor's Corporation, "Hawaiian Electric Industries Inc.," *RatingsDirect* (Mar. 28, 2003).
[18] Standard & Poor's Corporation, "Industry Report Card: U.S. Thrift Institutions Show Solid Third-Quarter Performance," *RatingsDirect* (Dec. 27, 2005).
[19] Fleishman, Steve and Kania, Alex, "Managing through the flat yield curve; still expensive," Merrill Lynch (May 15, 2006).
[20] Standard & Poor's Corporation, "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised," *RatingsDirect* (Jun. 2, 2004); Standard & Poor's Corporation, "Issuer Ranking: U.S. Utility And Power Companies, Strongest To Weakest," *RatingsDirect* (Oct. 27, 2006).
[21] Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (Nov. 22, 2006).
[22] Standard & Poor's Corporation, "Hawaiian Electric Company, Inc.," *RatingsDirect* (Aug. 30, 2006).
[23] Moody's Investors Service, "Liquidity Risk Assessment: Hawaiian Electric Industries, Inc.," *Global Credit Research* (Sep. 6, 2005, Apr. 18, 2006).
[24] See *e.g.*, Parker, David E., "4Q05 EPS Rebound with Utility Rate Relief, Maintain Outperform Rating," Robert W. Baird & Co. (Jan. 31, 2006); Bellessa, James L. and Nicholls, Brian H., "Hawaiian Electric Industries, Inc.," D.A. Davidson & Co. (Apr. 25, 2006); Fleishman, Steve and Kania, Alex, "Looking to More Rate Relief," Merrill Lynch (Feb. 9, 2006).

concluded that core utility and banking operations offer diversification that may insulate HEI's investors from the impact of changing interest rates.[25]

19. The investment community continues to focus on HEI's exposure to potential weakness in Hawaii's economy, however, there is no indication that this risk exposure has been significantly magnified by non-utility operations. For example, while the aftermath of the September 11, 2001 terrorist attacks resulted in an economic slowdown due to decreased tourism, investors made no distinction between HEI's core regulated utility and banking operations in their assessment of the effects of the downturn.

20. While the investment community has recently expressed some concern regarding higher debt levels in HECO's capital structure and deterioration in other financial measures, these developments have been attributed strictly to the challenges faced by HEI's regulated utility operations. As S&P noted, for example:

> HEI's consolidated financial condition remains weak for the rating despite the strong Hawaiian economy and the company's efforts in recent years to strengthen its capital structure. Financial metrics have been pressured owing to rising operating and maintenance expenses, increasing capital outlays, and the prolonged lack of rate relief.[26]

Meanwhile, S&P reported that in the third-quarter of 2006 ASB began to pay nearly all of its earnings as dividends to HEI, while sustaining its target core capital ratio and supporting its own business needs.[27]

21. The methodology used to establish the allowed rate of return for HECO and its electric utility subsidiaries avoids any bias that might be introduced by the specific risks of HEI's diversified activities. This is because the cost of equity has consistently been established by reference to groups composed of other comparable utilities. The Thomas Report noted that this insulates ratepayers from the impact of diversified activities because "any changes to HEI's cost of equity in the past have not been reflected in the revenue requirements used to set HECO's rates."[28]

This approach has been consistently followed in prior proceedings, including HECO's last rate case in Docket No. 04-0113, and it is my understanding that this approach will also be followed in HECO's current rate case.

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[25] See, *e.g.*, Fleichman, Steve, "Hawaiian Electric Industries Inc.," *Comment,* Merrill Lynch (Jul. 28, 2005).
[26] Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (May 31, 2006).
[27] Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (Nov. 22, 2006).
[28] Thomas Report at 131.

22. In conclusion, my review revealed no evidence that would alter the conclusions reached in the Thomas Report or indicate a fundamental change in investors' perceptions of the relationship between HEI and HECO. The comprehensive analyses conducted in preparing the Thomas Report required almost an entire year to complete and involved an exhaustive review of documents and extensive interviews with members of the investment community in Hawaii, on Wall Street, and in other financial centers. Given that the findings of such a comprehensive review with respect to the availability and cost of capital to HEI and its utility subsidiaries would not be expected to be materially different from those adopted by the PUC in December 1996, it is my opinion that the significant expenditure of time and money involved in conducting such a comprehensive review is not presently warranted.

Further Affiant sayeth not.

William E. Avera

Sworn and Subscribed before me this 18th day of December 2006:

Notary Public in and for
the State of Texas

ADRIEN MCKENZIE
MY COMMISSION EXPIRES
December 31, 2008
BONDED BY
NOTARY ASSOC. OF TEXAS, INC.

APPENDIX A

QUALIFICATIONS OF WILLIAM E. AVERA

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 200 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, and Wisconsin.

Testified in 40 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (75 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by

Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

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"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 1979)

"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

SAVINGS FROM REVENUE BONDS

The calculation of the estimated savings from financing with tax-exempt special purpose revenue bonds ("revenue bonds") instead of financing with "equivalent" taxable debt[1] is shown on the last page of this exhibit. A total savings of about $125 million is estimated for HECO's customers over the "original" life[2] of each of the revenue bonds that are currently outstanding. The savings calculation, which is required by Hawaii law[3], is similar to the calculations in Docket Nos. 04-0113 (HECO 2005 Test Year), 05-0315 (HELCO 2006 Test Year), and 97-0346 (MECO 1999 Test Year) in that it takes into account the economic differences between selling revenue bonds and equivalent taxable debt: interest costs, taxes, issuance costs (including any redemption costs), issuance discounts, revenue bond investment differentials, trustee fees, and deferred taxes.

Assumptions

In doing the calculation, we try to capture the material factors which affect the estimated savings. The estimated savings are based on assumptions regarding interest rates at the time of issuance and in the future over the life of the issuance. For example, we must make informed assumptions of interest rates and issuance costs of taxable debt since we didn't actually issue the taxable bonds and therefore, don't know what their costs would have been with any certainty. We also make assumptions for factors that are dependent on future conditions which can't be known with certainty, now. For example, we don't know for sure that a series of revenue bonds will be outstanding for its entire life, but for calculating savings, we assume they will be. As

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[1] Taxable debt with similar characteristics such as maturity date and call provisions.
[2] The life of a bond, assuming the bond remains outstanding until its original maturity date.
[3] Hawaii Revised Statutes Section 39A-208(b) and enabling legislation such as Act 206, 1998 Session Laws of Hawaii (Section 3).

another example, there are deferred tax effects that offset some of the savings, but the cost of the deferred tax difference depends on the rate of return on rate base in each year. We must make assumptions of the rate of return over the life of each series of revenue bonds in order to estimate the cost of the deferred tax difference.

Total Savings Versus Annual Savings

Estimated savings change from year to year over the life of a bond issue, mostly because of the impact of deferred taxes. Therefore, we have chosen to show total savings over the life of the bonds instead of savings on an annual basis.

Interest Costs

Revenue bonds have a lower interest cost than taxable debt with similar characteristics. The interest earned by buyers of revenue bonds is not taxable income for Federal or State of Hawaii income tax purposes (with some limited exceptions). This means that the revenue bonds can bear a lower interest rate than other forms of debt, and the owners of the bonds will still get the same after-tax return.

Column (D) of the savings calculation shows the revenue requirements of interest costs over the original lives of HECO's revenue bonds that are currently outstanding. It also shows the revenue requirements of estimated interest costs of equivalent taxable debt.

Amortized Costs and Trustee Fees

Issuance Costs: Revenue bonds currently have lower issuance costs than equivalent taxable debt, primarily because of the difference in underwriting fees and/or insurance costs. These fees are charged by underwriters for their work in carrying out marketing efforts for a bond sale and for taking the risk (with some exceptions) that they will be unable to resell the bonds without incurring a loss.

Issuance Discounts: Some revenue bonds were sold at a discount to secure a lower annual interest rate and reduce the overall cost of the bonds. These discounts are included in the total cost of revenue bonds. For taxable debt, we used interest rate estimates from underwriters based on issuances at par (that is, no discount). According to Goldman Sachs (the lead underwriter that we used for the most recent revenue bonds sold), taxable debt is commonly sold at par or with a small discount.

"Ongoing" Trustee Fees: Ongoing trustee fees consist of recurring annual fees from a bond trustee over the life of the bonds. Basically, bond trustees serve to protect the collective interest of the bondholders. As part of its duties, a bond trustee receives interest, principal, and redemption payments (if any) from the Companies and disburses them to bondholders. Ongoing trustee fees for revenue bonds are typically at about the same level as fees for equivalent taxable debt.

Construction Fund Trustee Fees: For revenue bond financings (except refunding issues), there are fees from construction fund trustees for managing the investment of undrawn revenue bond proceeds in the construction fund. These fees are generally expensed.

Column (E) of the savings calculation shows the total revenue requirements of issuance costs, redemption costs, issuance discounts, investment differentials, and trustee fees over the original lives of HECO's revenue bonds that are currently outstanding. It also shows the revenue requirements of estimated comparable costs of equivalent taxable debt.

Accumulated Deferred Taxes

Accumulated deferred tax balances reduce the Company's rate base. When assets are financed with revenue bonds, accumulated deferred tax balances are generally not as large as they would be if the assets were financed with other forms of debt. This is because assets financed with revenue bonds must be depreciated more slowly for tax purposes than if they had been financed with taxable debt. Thus, when assets are financed with revenue bonds, the result is that our tax depreciation is closer to our book depreciation, deferred taxes are less, and the rate base is higher than would be the case if those assets were financed with other types of debt. This increases revenue requirements somewhat, but for the revenue bonds HECO has issued, the deferred tax impact does not offset all of the savings from the interest rate reduction.

Column (F) of the savings calculation shows the revenue requirement effect of the average accumulated deferred tax balances of the assets estimated to be financed with revenue bonds. It also shows the same calculation assuming the assets were financed with equivalent taxable debt.

Conclusion

Clearly, some of the interest cost savings from revenue bonds are offset by other economic factors. However, it has been to the benefit of the Company's customers that revenue bonds finance part of the Company's construction program.

Hawaiian Electric Company, Inc.

Estimated Savings Due to Special Purpose Revenue Bond Financing
($ in Thousands)

	(A)	(B)	(C)	(D) = [(A)*(B)/(1-R)]*C	(E)	(F)	(G) = (D)+(E)+(F)	
				Revenue Requirements Over Original Life of Security *				
Series **	Interest Rate	Outstanding as of 12/31/05	Original Life (in years)	Interest	Amortized Costs and Trustee Fees	Average Accumulated Deferred Taxes	Total	
Costs of Financing with TAXABLE DEBT:								
Series 1993	7.30%	$ 50,000	30	$ 120,178	$ 672	$ (17,620)	$ 103,230	
Series 1996A	8.40%	48,000	30	132,755	702	(16,915)	116,542	
Series 1996B	7.75%	14,000	30	35,724	230	(4,934)	31,020	
Series 1997A	7.76%	50,000	30	127,751	599	(17,620)	110,730	
Refunding Series 1998A (1987)	6.75%	42,580	14	44,162	615	(8,452)	36,325	
Refunding Series 1999B (1988)	7.40%	30,000	19	46,293	872	(543)	46,622	
Series 1999C	7.85%	35,000	30	90,463	1,237	(12,334)	79,366	
Refunding Series 1999D (1990A)	7.80%	16,000	20	27,394	523	(304)	27,613	
Refunding Series 2000 (1990B&C)	7.75%	46,000	20	78,253	1,362	(874)	78,741	
Series 2002A	6.35%	40,000	30	83,631	12,232	(14,096)	81,767	
Refunding Series 2003B (1992)	5.65%	40,000	20	49,608	2,346	(761)	51,193	
Refunding Series 2005A (1995A)	5.25%	40,000	20	46,096	2,648	(761)	47,983	
		$ 451,580		$ 882,306	$ 24,038	$ (95,214)	**$ 811,130**	(H)
Costs of Financing with REVENUE BONDS:								
Series 1993	5.45%	$ 50,000	30	$ 89,722	$ 1,481	$ (1,391)	$ 89,812	
Series 1996A	6.20%	48,000	30	97,986	2,690	(1,336)	99,340	
Series 1996B	5 7/8%	14,000	30	27,081	691	(390)	27,382	
Series 1997A	5.65%	50,000	30	93,014	1,896	(1,392)	93,518	
Refunding Series 1998A (1987)	4.95%	42,580	14	32,385	998	(5,561)	27,822	
Refunding Series 1999B (1988)	5.75%	30,000	19	35,971	1,253	(543)	36,681	
Series 1999C	6.20%	35,000	30	71,448	1,278	(974)	71,752	
Refunding Series 1999D (1990A)	6.15%	16,000	20	21,599	523	(304)	21,818	
Refunding Series 2000 (1990B&C)	5.70%	46,000	20	57,554	1,488	(874)	58,168	
Series 2002A	5.10%	40,000	30	67,168	5,851	(1,113)	71,906	
Refunding Series 2003B (1992)	5.00%	40,000	20	43,901	1,764	(761)	44,904	
Refunding Series 2005A (1995A)	4.80%	40,000	20	42,145	2,051	(761)	43,435	
		$ 451,580		$ 679,974	$ 21,964	$ (15,400)	**$ 686,538**	(I)
Estimated Savings to Customers (over original life of revenue bonds) = (H)-(I)							**$ 124,592**	

* Revenue requirements = nontaxable expenses grossed up for revenue taxes (R), and taxable expenses grossed up for revenue taxes and income taxes. Refer to Docket No. 04-0113 (HECO 2005 Test Year), HECO-WP-2119, p.1 and p.4 for Amortized Costs/Trustee Fees and Average Accumulated Deferred Taxes calculations, respectively, for Series 1993, 1996A, and 1996B. Revenue Requirements information for other Series are contained in the "Estimated Savings From Special Purpose Revenue Bond Financing" document filed with the Commission for the respective Series.

** See reports on savings on file with the Commission.

Note: Totals may not add exactly due to rounding.

Filename: Rev Bond Savings Support.xls 1917 p.5 Revenue Bond Savings